PPIAF – Electricity Generation Standards

Final Report

July 31, 2006

Robert R. Richwine
Richwine Consulting Group
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<td>NTDC</td>
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<td>PEPA</td>
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<td>PGP</td>
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<tr>
<td>PH</td>
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<td>POH</td>
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<td>PPIAF</td>
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<td>RAM</td>
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<tr>
<td>RC</td>
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<tr>
<td>SH</td>
</tr>
<tr>
<td>TOR</td>
</tr>
<tr>
<td>UOH</td>
</tr>
<tr>
<td>WAPDA</td>
</tr>
<tr>
<td>WEC</td>
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1. Introduction

1. This report is intended to describe the results of a Public-Private Infrastructure Advisory Facility (PPIAF) study conducted in accordance with the Contract signed between the World Bank and Robert R. Richwine Consulting Group, which Contract incorporates the Bank’s Terms of Reference (TOR). National Electric Power Regulatory Authority (NEPRA) is the prime recipient / beneficiary of the study.

2. The Consultant understands that Pakistan is in transition towards a more competitive, market-based electric power sector, and that this project is one of the necessary steps required to make that transition as smooth and cost-effective as possible. An intermediate step is to define meaningful Key Performance Indicators (KPIs) for various generation parameters and to help NEPRA establish a set of standards for those indicators that NEPRA can monitor and enforce. While establishing the goals and expectations for those indicators it will be necessary to provide realistic expectations for Pakistan’s plants in the near term to ensure that they can be achieved without large investment requirements and dramatic rate shocks to the customers. In addition the “industry best practices” levels of performance which might be the long-term goals should be identified where possible. Although the primary focus is on power plant reliability, availability, efficiency and safety, other performance areas were considered for completeness. Comparisons with other countries standards are also provided.

3. The detailed Terms of Reference is included as Appendix 1.
II. Existing Conditions

State of Power Generation Plants in Pakistan

4. After reviewing the load forecasts and available capacity data for Pakistan provided in a presentation made by NEPRA during the Consultant’s Inception visit in April, 2006 and discussions with several stakeholders, it is apparent to the consultant that Pakistan will soon need to recover as much lost energy producing capability as possible from its existing generating facilities. This can be done in two ways: 1) Recover lost capacity (the difference between Installed Capacity and Dependable Capacity) and 2) Improve the availability of that capacity. Currently, other projects are attempting to identify ways to regain the lost capacity while this project attempts to identify ways to improve plant availability (as well as other performance parameters). Figure-1 describes the difference between these two complementary approaches.

Figure-1: Installed and Dependable Capacity at different Availability Levels

<table>
<thead>
<tr>
<th>cargar el</th>
<th>Instalada Capacidad @ 100% Disponibilidad</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amount of lost capacity attempted to be regained with other projects</td>
<td></td>
</tr>
<tr>
<td>Dependable Capacidad @ 100% Disponibilidad</td>
<td></td>
</tr>
<tr>
<td>Gap between 100% availability and optimum availability (Not cost-effective to regain)</td>
<td></td>
</tr>
<tr>
<td>Dependable Capacidad @ Optimum Disponibilidad</td>
<td></td>
</tr>
<tr>
<td>Amount of “Equivalent” lost capacity due to low availability attempted to be regained (through recommendations under this Study)</td>
<td></td>
</tr>
<tr>
<td>Dependable Capacidad @ Current Disponibilidad</td>
<td></td>
</tr>
</tbody>
</table>

5. In Figure-1, the gap between installed capacity and the current dependable capacity is being addressed by other initiatives and not specifically by this project. This project does address quantifying the amount of potential “equivalent energy producing capability increase” that can be cost-effectively achieved by improving the availability of existing electricity generating units.
in Pakistan to optimum levels. In addition this project will seek to find corresponding levels of potential and cost-effective improvement in other performance parameters. With a total installed capacity in Pakistan of 17,975 MW each 1% improvement in Availability that can be achieved and sustained is equivalent to approximately 211 MW of new capacity at 85% availability. To arrive at that figure we calculate the Available Capacity as the product of the capacity times the availability. Therefore a 1% improvement in Availability would result in a 179.75 MW increase in Available Capacity if that capacity were 100% available. A more realistic availability goal might be 85% so that the 179.75 MW at 100% availability would be equal to 211 MW at 85% availability (179.75/0.85). However, it is also apparent that not all plants and sectors have equal opportunity to achieve the same levels of cost-effective availability improvement.

6. Even with only minimal performance data currently available from Pakistan’s plants in a form that can be compared to international peers, it is clear that substantial opportunity exists for sustainable and cost-effective availability improvement in certain areas, namely the thermal plants in the public sector. Table-1 gives availability data for the plants providing information to the consultant:

<table>
<thead>
<tr>
<th>Availability Factor (2005)</th>
<th>Public</th>
<th>IPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Fossil Steam</td>
<td>58%</td>
<td>84%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>74%</td>
</tr>
<tr>
<td>Large Fossil Steam</td>
<td>76%</td>
<td>82%</td>
</tr>
<tr>
<td>Small Combined Cycle</td>
<td>90.5%</td>
<td>84%</td>
</tr>
<tr>
<td>Large Combined Cycle</td>
<td>2@</td>
<td>90%</td>
</tr>
<tr>
<td>Hydro</td>
<td>91.5%</td>
<td></td>
</tr>
<tr>
<td>Diesel</td>
<td></td>
<td>93%</td>
</tr>
</tbody>
</table>

Source: Plant Data and Consultant Estimates

7. Although the data in the above Table is for only four (4) public sector and seven (7) private sector plants, discussions with various stakeholders have led the consultant to anticipate that most of the availability can be expected to come from the 6565 MW of public sector thermal plants. Following the rationale in the preceding paragraph, a 1% improvement in availability at these plants would be equivalent to approximately 77 MW of new capacity that had an availability of 85 percent (65.65/0.85). If the total availability improvement that can be achieved and sustained is 15%, then the total equivalent capacity represented by this availability improvement would be 1155MW. The assumption of 15% was made by the consultant based on the limited data available and the performance of their peers in other parts of the world, and considering the unique set of conditions in Pakistan. It should be noted, however, that this improvement does not happen overnight, but rather is a process that takes place over several years. The time required for the performance improvement can be minimized by taking advantage of other company’s experiences to “get down the learning curve” as quickly as possible. While every country has its own unique set of conditions, challenges and opportunities, many valuable lessons can be learned from studying other company’s successful programs (Ref 2, 6).
8. Other important conditions that the consultant observed include the following:

a) There appears to be substantial inconsistency in the performance data that is currently being collected so that its potential for use in improving performance is not being fully exploited.

b) It appears unlikely that the cause/effect relationships between various short-term operational characteristics (such as cycling, low-load operation, etc.) are fully incorporated into dispatch decisions, where industry studies have shown will lead to long-term lower reliability and higher cost consequences.

c) There is a strong interest and desire on the part of the plant staff to find ways to improve the performance of their power plant.

d) There is a perceived lack of incentives for performance improvement that appears to be fairly common among the stakeholders.

e) Extended outages are often caused by the inability to obtain required spares in a timely manner.

f) Except for the IPPs, there seems to be little awareness of the true value of plant performance improvement.

g) During the workshops conducted in Lahore and Karachi during the week of July 10, 2006, data was presented using the recommended methodology for the public sector thermal plants for the month of January 2006, indicating the ability of Pakistan’s plants to collect and compile this data.

h) The IPPs are unsure how, or if, the new NEPRA performance standards would apply to them, and if they would conflict with the provisions of their Power Purchase Agreements.

9. Based on numerous examples of successful improvement efforts around the world in both developing and developed countries, the availability improvement should be able to be achieved for about 25% of the cost of a new plant since the majority (estimated between 75-80 %) would be accomplished through improved management practices (Reference 3). Although it can be expected that some additional money will be required to replace equipment, without management improvement the effect will be short-lived. Furthermore, if the management practices are not improved, the recovery of lost capacity being addressed by other projects is unlikely to achieve or sustain its full potential. In addition as new technologies are introduced into Pakistan with their inherently greater efficiencies (with reduced fuel costs and improved environmental performance), they are also unlikely to achieve their full potential without management improvements.

10. The primary management improvement area that has taken place at companies around the world who have improved their performance can be described as moving the mindset of the entire plant staff from a reactive style to a proactive style. Anticipating potential future problems and devising plans to prevent, detect or mitigate the effects of malfunctions has led, over and over again, to substantially improved performance.

11. Other performance areas, especially efficiency, safety, cost and environmental performance, have also used this mindset shift to achieve improvement in these areas. In fact studies and
statistical evidence (primarily from the Nuclear Industry) have shown clear linkages between all of these performance areas.

12. One of the key initiatives common in companies who have achieved and sustained performance improvement is the implementation of a strong data collection and analysis program. The World Energy Council’s website [www.worldenergy.org/forward.asp?page=pgp](http://www.worldenergy.org/forward.asp?page=pgp) contains over 30 case studies that describe dozens of examples of ways performance data has been used to help improve performance. One of the key recommendations in this Standards Project will be to create a performance data collection system (or a use data collection system developed elsewhere). While defining this system, NEPRA should recognize the wider uses in which the data can be used to help improve performance and ensure that the maximum possible value can be obtained from the program. For those companies who are searching for proven ways to improve their performance it is suggested that they pay particular attention to the four WEC case studies for the months of January, February., March and April of 2003 (Ref 4).
III. Methodology and Approach to Performance Standards

International Experience

13. To create performance standards (benchmarks), the international power generation industry typically follows three basic steps:

   a) Decide which performance parameters are appropriate to benchmark and where the data for similar plants will be obtained.

   b) Select which plants have similar design and operational characteristics to the candidate plant and establish peer groups.

   c) Compile the ranges of the selected performance parameters for each of the peer groups.

14. Step a) is necessarily interactive since it might be desirable to select a particular performance parameter, but without a credible data base for that parameter, it would be very difficult to set an objective standard.

15. Step b) is often a much more difficult process than commonly recognized. For example, detail statistical analysis has conclusively demonstrated that mode of operations (base load versus cycling) is usually much more influential on plant reliability than size or fuel type when selecting peer plants (Ref. 5). Therefore, if mode of operation was not used as select criteria for peer selection, an inappropriate peer group might be selected and invalid benchmarks selected.

16. Once the parameters are selected and the appropriate data bases are compiled, it is typical for the standard to be set at some percentile (often the best quartile) of the peer group frequency distribution. Best quartile is the point where 75% of the plants in the peer group have poorer performance and 25% have better performance.

17. As an example, the distribution of the five year average Equivalent Availability Factor (EAF) of a certain group of peer units reporting their Reliability, Availability, Maintainability (RAM) data to the North American Electric Reliability Council’s (NERC) Generating Availability Data System (GADS) is shown in Figure-2.

18. From this graph, we can see that the best quartile (75th percentile) performance of the Energy Availability Factor (EAF) is at ~ 89%. If the candidate power plant’s EAF is substantially below that value we might select a lower value initially (perhaps the 50th percentile value of 85%), then establish 89% as a long range goal. Of course if our plants have exhibited a much lower availability over several years, we might set more realistic (lower) initial goals.
In addition to comparing the current levels of local plant performance to international standards, it is important to account for local conditions that will influence reliability to a greater or lesser extent than the conditions that exist for the international best performers (those at or above the best quartile of performance). Among the factors that should be adjusted for are 1) design versus actual mode of operations and dispatch variability, 2) fuel supply constraints (although a good data system should be able to account for factors outside management control), 3) difficulty in parts supply and economic considerations in determining the optimal spare parts inventory levels, 4) grid instability resulting in greater stresses on the plant equipment and other local factors, 5) inadequate resources (time, money, skilled manpower) available and 5) other factors making it more difficult for Pakistan’s power plants to achieve superior performance. While it is difficult to normalize the performance data for many of these factors, some effort should be made to consider them in setting values for the various standards. This is not to afford Pakistan’s plants an easy excuse for poor performance. Other countries have experienced many of the same issues and have been able to overcome them. (Ref. 2 & 6). Rather it is intended to allow the setting of realistic and achievable performance goals.
IV. Generation Parameters Considered for Standards

20. Discussions with NEPRA categorized generation performance standards into three types:

a) **1st set** – technical parameters (voltage, frequency, harmonics and reactive power, interconnection to grid, etc) and other national standards (environmental compliance, safety, etc), which would be mandatory on all generation plants;

b) **2nd set** – plant availability and energy generation capability standards, where comparative data would be made available through the software, and generation plants could be incentivized to improve performance; and

c) **3rd set** – efficiency-related standards (combustion efficiency and heat rate, auxiliary consumption, fuel-choices and upgrades, etc) and cost-related standards (if feasible), which would be for indicative purposes only.

1st Set – Technical Parameters and other National Standards

Power Quality Standards

21. These technical parameters (voltage, harmonics, etc) are both vital and complex. Appendix-2 gives examples from other countries of the Power Quality standards they have developed. An in-depth project, using these and other examples, will be required to develop Pakistan specific standards for Power Quality.

Environmental Standards

22. Environmental standards for Pakistan emissions, liquid and gaseous fuel handling and utilization, etc., can be found in the Pakistan EPA website. These standards can be found in Appendix 3.

Safety Standards

23. The development of detailed safety standards for Pakistan’s power plants will require an in-depth project. The consultant has been unable to locate safety standards for other countries.

2nd SET – Reliability, Availability, Maintainability (RAM) Standards

24. Based on the study objectives listed earlier is Section II, these performance standards (plus efficiency and safety) are the primary focus of this study. For developing RAM standards the following aspects must be considered:

a) Performance indicators (technology-wise) need to be few in number, but best represent the overall performance of the generating units.

b) Performance indicators which are measurable, quantifiable and controllable by the licensees; and enforceable by the regulator.
25. After considering many of the RAM performance parameters from the upcoming World Energy Council’s (WEC) Power Plant Performance Data Collection System (see Appendix 5 & 6 for current version, pending final approval, of the WEC’s design and performance data system elements), the consultant believes that the following three indicators best meet the above requirements at this time (as Pakistan moves to a more competitive business environment other, more market-based indicators, will supplement or replace these. See Section 7 for a more complete discussion of this aspect):

a) **Energy Loss Rate (ELR)** – this indicator has been a key metric for determining the likelihood (probability) that a generating unit will deliver its rated capacity at any particular time. It is commonly used in many countries around the world to 1) plan the future installed capacity required to meet optimal customer service reliability requirements and 2) evaluate the historic performance of power plants. This indicator is very similar to the North American Electric Reliability Council’s (NERC) indicator Equivalent Forced Outage Rate (EFOR).

\[
ELR = \frac{(UOH + EUDH)}{(SH + UOH)}
\]

Where:
- **UOH = Unplanned Outage Hours** – the sum of all hours the unit was off-line due to unplanned outages and startup failure outages.
- **EUDH = Equivalent Unplanned Derated Hours** – The sum of all equivalent hours the unit was temporarily reduced (restricted, derated) due to Unplanned Deratings. These hours are computed from deratings (restrictions) only and do not include full, complete outage hours. To compute equivalent hours: Each individual Unplanned Derating is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Reference Capacity (RC). These equivalent hour(s) are then summed.

\[
\text{De-rating Hours} \times \text{Size of Reduction} \over \text{RC}
\]

The “size of reduction” is reference capacity minus temporary capacity as a result of the derating or restriction

**Reference Capacity (RC) (MW)**

RC is the unit’s maximum dependable generating capacity less any station service or auxiliary power requirements (in MW). RC is determined when there are no short term equipment problems causing a temporary derating of the unit and all major equipment is operating at full load under designed temperatures and pressures
SH = Service Hours – number of hours the unit was synchronized to the system. For units equipped with multiple generators, only those hours are counted when at least one of the generators was synchronized, whether or not one or more generators were actually in service.

b) **Energy Availability Factor (EAF)** – this indicator has been historically been used even longer than ELR or EFOR. But because it is a “factor” (the denominator is period hours) as opposed to ELR/EFOR being “rates” it does not reflect the demand on the unit. So that a low demand unit gains “availability” credit even when it is not exposed to potential failures. However, even with this limitation, EAF is commonly used to assess performance since it incorporates both planned and unplanned outages. Energy Availability Factor is virtually identical to NERC’s Equivalent Availability Factor which also carries the abbreviation EAF.

\[
EAF= \frac{(AH - EUDH - EPDH)}{PH}
\]

Where:
- **AH = Available hours** – the sum of the Unit Service Hours, Reserve Shutdown Hours, Pumping Hours (if applicable), and Synchronous Condensing Hours (if applicable).
- **EUDH = Equivalent Unplanned Derated Hours** (see definition under ELR above)
- **EPDH = Equivalent Planned Derated Hours (EPDH)** –

The sum of all equivalent hours the unit was temporarily reduced (restricted, derated) from its Reference Capacity due to Planned Deratings. These hours are computed from deratings (restrictions) only and do not include full, complete outage hours.

To compute equivalent hours: Each individual Planned Derating is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Reference Capacity (RC). These equivalent hour(s) are then summed.

\[
\text{Derating Hours} \times \frac{\text{Size of Reduction}}{\text{RC}}
\]

The “size of reduction” is reference capability minus temporary capability as a result of the derating or restriction.

**Period Hours (PH)** – The number of hours in the defined time period that the unit was in the **active** state (not retired or mothballed, etc.). The sum of Available Hours and Unavailable Hours must equal Period Hours.

c) **Planned Outage Factor (POF)** – This metric gives an indication of the amount of time the generating unit spent in the unavailable state due to planned outages (planned well in advance such as annual maintenance outages).
EPOH = POH/PH

Where:
POH = Planned Outage Hours – the sum of all hours the unit was off-line due to Planned Outages (Outages planned well in advance such as annual overhauls).

PH = Period Hours (see definition above)

d) Comparison of RAM terminologies – WEC and NERC use different RAM terms, and power plants in Pakistan may be used to altogether different terms. Table-2 provides a comparison of these terms for the sake of greater clarity

<table>
<thead>
<tr>
<th>WEC Term</th>
<th>NERC Term</th>
<th>Pakistan Term</th>
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<tbody>
<tr>
<td>ELR</td>
<td>EFOR</td>
<td>to be provided by NEPRA</td>
</tr>
<tr>
<td>EAF</td>
<td>EAF</td>
<td>to be provided by NEPRA</td>
</tr>
<tr>
<td>POF</td>
<td>POF</td>
<td>to be provided by NEPRA</td>
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</table>

Range determination for RAM indicators

26. In the future the World Energy Council (WEC) will collect and publish these RAM indicators for power plants around the world. At that time NEPRA will be able to access worldwide data for setting the RAM standards. For the present the RAM standards in Pakistan can be set by developing the range of these indicators for comparable plants in the United States using the North American Electric Reliability Council’s (NERC) Generating Availability Data System (GADS) containing over 20 years of RAM data for over 5000 generating units in North America. In addition the GADS system has been provided free of charge and is now being used in over a dozed countries including the Peoples Republic of China, Canada, Saudi Arabia, Malaysia, India, Italy and others. While not all countries report their data to NERC, those that do will have their data incorporated into the GADS database which is easily accessed by the NERC developed benchmarking software program pc-GAR which will be the model for the WEC’s future benchmarking software. It should also be understood that both the WEC and NERC databases are based on unit level data, not plant level. This has been shown to be vital in order to maximize the value of the RAM data.

3rd SET – Efficiency and Cost Standards

Efficiency Standards

27. Setting rational and meaningful efficiency (heat rate) standards is such a difficult and complex process that very few, if any, countries have tried to implement them. To better understand the problems in setting heat rate standards, the following is a brief description of some of those difficulties.
28. Each unit has a “Design Heat Rate Curve”, based on its technology, equipment configuration, ambient conditions, fuel type and quality and other design-type factors. This curve typically shows that the unit is less efficient at some load points than others. For example, a fossil steam unit is substantially less efficient (higher heat rate) at its minimum load point than when it is running at its normal full rated capacity. In addition, during startups the fuel consumption is much greater per unit of electricity generated. Therefore, it is clear that a unit’s heat rate over some period of time is highly dependent on the way the system has dispatched it. Frequent startups and/or running a large percentage of hours at minimum load will cause the unit to use much more fuel and have a much higher heat rate than an identical unit with the same load (capacity) factor but that ran virtually at full capacity (but for fewer hours giving the same load factor). Furthermore, actual ambient air and water temperatures variations at the times of dispatch will also affect the plant’s efficiency.

29. Some companies, however, have been able to establish a rational way to evaluate the efficiencies if its power plants. They first take each unit’s unique “Design Heat Rate Curve” and adjust it for ambient conditions and fuel type, time since overhaul, etc. Standard adjustment factors are usually supplied by the Original Equipment Manufacturer or Architect/Engineer. This gives a new curve called the unit’s “Theoretical Best Achievable Heat Rate Curve” which implies that if all factors not under management control were adjusted for, this would be the absolute best efficiency the plant could achieve at its various load points. This is analogous to an Energy Availability Factor (EAF) of 100% or an Energy Loss Rate (ELR) of 0%; that is, the very best that could possibly be achieved.

30. However, just as it can be demonstrated that it is not cost-effective for a plant to spend the money necessary to achieve a perfect EAF or ELR (see Reference 1) it is also recognized that it is not cost-effective for a plant to be at its theoretical best achievable heat rate. Some deviation should be expected. Depending on the technology, the amount the unit is called on to generate and its fuel cost, the unit’s “deviation from theoretical best achievable” goal has often been set between 2-4 percent. A high load factor unit can economically justify more expenditure to achieve a lower deviation while a high fuel cost unit can also justify more but will probably generate less in an economic dispatch system. The whole idea is to set a standard for the plant’s efficiency on the basis of 1) what is under management control and 2) what is cost-effective.

31. The unit can then be periodically tested to determine its actual heat rate curve and compared to the theoretical best achievable heat rate curve (with appropriate adjustments to the design heat rate curve as described above). At many companies this process is routinely done as a part of its normal unit testing program for use in its dispatch optimization process. If this test data is gathered for Pakistan’s plants by the dispatch organization, it potentially could be used in this application. Figure-3 is a typical example of the heat rate versus MW output for the unit’s Design, Theoretical Best Achievable, and Deviation from Theoretical Best Achievable curves.
Power plant costs have traditionally been an extremely difficult aspect of a plant’s performance to benchmark and set standards, especially when attempting to compare data across international borders. In addition to the differences inherent in differing technologies, operating regimes, age, fuel types, economies of scale, etc., there are also issues such as labor rates and productivity differences (sometimes even within a single country), equipment costs, tax structures, environmental requirements, inflation rates and monetary exchange rates. In addition most private companies are reluctant to publish cost figures, believing that this could put them at a competitive disadvantage. When costs have been compared it is common to use the following indicators to benchmark costs:

1) Fuel Costs – measured in $ (or local currency) per MW-HR
2) Non-Fuel Costs – measured in $ per MW-HR and $ per KW of installed capacity
3) Productivity Measures – measured in employees per MW and MW-HR per employee

33. The International Atomic Energy Agency (IAEA) does have a cost data collection system for nuclear plants that it has had in place for several years, using the cost data collection system developed by the EUCG (formally known as the Electric Utility Cost Group), a not-for-profit association of electric utilities, originally from North America, but now including members from international utilities.

34. Since the IAEA’s database is only for nuclear plants, its value is limited in Pakistan. However, the possibility exists for Pakistan to become a member of the EUCG and share cost data using the EUCG’s data collection system. There are also private cost data systems available through a variety of companies, including Soloman Associates, Navigant Consulting and others. The only public domain cost data base that the project consultant is aware of is one for regulated United States electric utilities where cost reporting to the U.S. Federal Energy Regulatory Commission (FERC) is mandatory and the data is published annually. Accessing and analyzing this database is a fairly complex process, especially when attempting to normalize the US cost data to Pakistan conditions.
V. Recommended Performance Standards

35. Based on the foregoing discussion, and in keeping with the international practice, the Consultant recommends to NEPRA three sets of performance standards, which may be subject to mandatory or voluntary regulation. For the second set of performance standards, necessary incentives need to be created so as to encourage power plants to improve performance. Table-3 provides the summary of these performance benchmarks.

Table-3: Summary of Recommended Performance Standards

<table>
<thead>
<tr>
<th>Type</th>
<th>Description</th>
<th>Nature of Compliance</th>
<th>Regulatory Instrument</th>
<th>Who Regulates?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Quality</td>
<td>1. Voltage stability</td>
<td>Mandatory</td>
<td>Power Purchase Agreement (PPA)</td>
<td>Contracting parties; NEPRA oversees</td>
</tr>
<tr>
<td></td>
<td>2. Turbine Governor Operation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Reactive Power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4. Frequency</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental</td>
<td>1. Air Emissions</td>
<td>Mandatory</td>
<td>National Environmental Quality Standards (NEQS)</td>
<td>Pakistan (provincial) Environmental Protection Agency</td>
</tr>
<tr>
<td></td>
<td>2. Liquid and gaseous fuel handling and consumption</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Waste disposal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4. Others</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Safety</td>
<td>1. Lost time accident rates</td>
<td>Mandatory</td>
<td>Safety standards for power generation plants need to be revised and re-notified</td>
<td>Safety Inspector, Provincial Department of Industries &amp; Labor</td>
</tr>
<tr>
<td></td>
<td>2. Near Misses</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Vehicle accident rates</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reliability, Availability, Maintenance (RAM)</td>
<td>1. Energy Loss Rate</td>
<td>As per PPA; incentives for better than expected performance</td>
<td>Power Purchase Agreement, plus Incentives Notification to be issued by NEPRA</td>
<td>Contracting parties; NEPRA oversees</td>
</tr>
<tr>
<td></td>
<td>2. Energy Availability Factor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Planned Outage Factor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Efficiency</td>
<td>1. Deviation from theoretical best achievable heat rate</td>
<td>As per PPA; incentives for better than expected performance</td>
<td>Power Purchase Agreement, plus Incentives Notification to be issued by NEPRA</td>
<td>Contracting parties; NEPRA oversees</td>
</tr>
<tr>
<td></td>
<td>2. Auxiliary Consumption</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Costs</td>
<td>1. Average unit fuel cost</td>
<td>As per PPA; incentives for better than expected performance</td>
<td>Power Purchase Agreement, plus Incentives Notification to be issued by NEPRA</td>
<td>Contracting parties; NEPRA oversees</td>
</tr>
<tr>
<td></td>
<td>2. Average unit non-fuel cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3. Productivity measures</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Power Quality Standards

36. Power quality (voltage, reactive power, frequency, etc.) is technical in nature, and plants are obligated to adhere to these standards in all cases. There are severe consequences on the stability of the overall system, and therefore performance in this area can not be allowed to deteriorate. Appendix-2 provides a comparison of power quality standards of Pakistan and several other countries, and Table-4 provides the summary of these standards.
### Table-4: Summary of Power Quality Standards

<table>
<thead>
<tr>
<th>Description</th>
<th>Pakistan</th>
<th>North America</th>
<th>Europe (National Power, UK)</th>
<th>Developing Country</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage stability</td>
<td>Plus or minus 10 percent</td>
<td>See Appendix 2</td>
<td>From IEC or BS standards (fee based data)</td>
<td>unavailable</td>
</tr>
<tr>
<td>Turbine Governor Operation</td>
<td>Droop adjusted from 95% to 105%</td>
<td>See Appendix 2</td>
<td>IEC or BS standards (fee based)</td>
<td>unavailable</td>
</tr>
<tr>
<td>Reactive Capacity</td>
<td>See Appendix 2</td>
<td>See Appendix 2</td>
<td>IEC or BS standards (fee based)</td>
<td>unavailable</td>
</tr>
<tr>
<td>Frequency</td>
<td>See Appendix 2</td>
<td>See Appendix 2</td>
<td>IEC or BS standards (fee based)</td>
<td>unavailable</td>
</tr>
</tbody>
</table>

37. It is recommended that NEPRA create a task force of power quality specialists in Pakistan to review in detail the power quality standards (voltage, reactive power, frequency, etc.) from other countries contained in the Appendices to this report as well as standards from other countries. Once a comprehensive list of power quality indicators are agreed upon and the long-term goals for those indicators are set, a method for testing Pakistan plants should be devised to determine the current gap between power quality levels and the long-term goals can be determined. If the current gap is large, intermediate power quality goals might be established, leading to the achievement of long term goals.

### Environmental Standards

Comprehensive environmental standards exist in Pakistan (Appendix-3) in the form of National Environmental Quality Standards (NEQS). These pertain to air emission, liquid and gaseous fuel handling and consumption, and other possible contaminations. These standards were notified by the Government in year 2000, and compliance is envisaged to be ensured through the Federal and Provincial Environmental Protection Authority (EPA).

38. It is recommended that NEPRA conform to the environmental standards found in the Pakistan EPA website and the National Environmental Quality Standards.

### Safety Standards

39. The Consultant has been unable to find published national safety standards which are specific for power generation plants. However, Occupational Health and Safety issues are assuming increasing significance and power plants are compiling plant safety data. Generally, plants tend to set a goal of 0 lost time accident or fatalities and do not recognize a higher value as an acceptable level. Some plants do collect data on safety indicators such as Lost Time Accident Rates, Fatalities, and Near Misses.

40. It is recommended that NEPRA create a task force of safety specialists in Pakistan to determine what safety indicators should be used. Once a comprehensive set of safety indicators are agreed upon, data from Pakistan plants should be collected relating to those indicators so that
the current safety levels can be determined. Pakistan’s safety records can then be compared to surveys taken at other countries to determine what actions should be taken.

**Reliability, Availability, Maintainability (RAM) Standards**

41. Based on prevalent international practice, and in keeping with the objective of enhancing the performance of the power plants in Pakistan, the following three standards are being recommended:

a) Reliability Indicator: Energy Loss Rate (ELR);
b) Availability Indicator: Energy Availability Factor (EAF); and
c) Maintainability Indicator: Planned Outage Factor (POF).

42. Taken together these three Key Performance Indicators (KPIs) will best represent the overall RAM performance of the generating units in today’s business environment in Pakistan and are measurable, quantifiable and controllable by the licensees and enforceable by the regulator.

43. Appendix -5 gives benchmarking data (ranges) for plants comparable to Pakistan’s power generating units based on the data in the North American Electric Reliability Council’s Generating Availability Data System. A brief summary of these benchmarks is given in Table-5. The ranges for the North American plants are for the 25$^{th}$ to 75$^{th}$ percentiles.

**Table-5: Summary of Major RAM Indicators**

<table>
<thead>
<tr>
<th>Description</th>
<th>Pakistan (Range for different plants)</th>
<th>North America (Ranges)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Small Fossil Steam Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>AF range 57.65% - 84.43%</td>
<td>2.71% - 8.71%</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>85.24% - 92.62%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>3.08% - 7.34%</td>
</tr>
<tr>
<td><strong>Large Fossil Steam Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>AF = 75.68% (data for 1 plant only)</td>
<td>5.92% - 11.34%</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>81.40% - 89.59%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>4.40% - 11.22%</td>
</tr>
<tr>
<td><strong>Small Combined Cycle Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>AF = 84.43 (1 plant only)</td>
<td>5.27% - 18.01%</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>81.85% - 92.89%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>1.13% - 8.82%</td>
</tr>
<tr>
<td><strong>Large Combined Cycle Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>AF range 89.93 – 90.47 (2 plants only)</td>
<td>4.16% - 23.20%</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>81.79% - 93.02%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>1.73% - 7.90%</td>
</tr>
<tr>
<td><strong>Hydroelectric Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>EAF = 91.48% (1 plant only)</td>
<td>0.94% - 2.82%</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>84.42% - 93.74%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>4.52% - 11.30%</td>
</tr>
<tr>
<td><strong>Diesel Units:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss Rate</td>
<td>No data</td>
<td>-</td>
</tr>
<tr>
<td>Energy Availability Factor</td>
<td></td>
<td>92.43% - 99.32%</td>
</tr>
<tr>
<td>Planned Outage Factor</td>
<td></td>
<td>-</td>
</tr>
</tbody>
</table>
Efficiency Standards

44. It is recommended that NEPRA take advantage of current plant heat rate test data from other sources in Pakistan such as the National Load Dispatch Centre (if it has access to such data), or create a heat rate testing program along the lines discussed in the section on Efficiency Standards. Comparisons of that actual data with the “theoretical best achievable heat rate” (taken from each unit’s unique design heat rate curve and adjusted for actual ambient conditions, age, dispatch, fuel, etc) will give NEPRA an understanding as to the current efficiency gap of its power plants. An “Optimum Economic Efficiency” goal for each plant can then be estimated (which might be in the range of 2-4 % deviation from the theoretical best achievable heat rate – see earlier discussion on efficiency standards) and a time frame developed for meeting that goal. If the current gap is large, intermediate efficiency goals might be established allowing the final goal to be gradually achieved over time so that it does not lead to huge investment requirements and dramatic rate shocks to the consumers.

Cost Standards

45. It is recommended that NEPRA consider becoming involved with ongoing international cost data collection and analysis efforts. Although the issues associated with cost are complex and especially difficult across international borders, the potential value is great, as many companies who have undertaken this activity have discovered. While commercial cost benchmarking companies might provide immediate help, their cost may be too high at this time. Instead, it is recommended that NEPRA and the public generating companies in Pakistan investigate membership in the international arm of the EUCG. Attending its semi-annual meetings and interacting with others with similar interests from around the world in person and by electronic means will create a much better understanding of the potential for cost reductions using cost benchmarking methodologies. At that time NEPRA will be in a much better position to make an informed decision regarding cost standards that are appropriate for Pakistan’s power plants.
VI. Implementation

Power Quality Standards

46. NEPRA should create a task force of power quality experts in Pakistan to review power quality standards contained in the Appendices to this report as well as other they can gain access to, in order to determine the appropriate power quality standards for Pakistan.

Environmental Standards

47. NEPRA should review in depth the environmental requirements in the EPA website and decide which ones would be appropriate to include as part of the NEPRA generation performance standards

Safety Standards

48. NEPRA should create a task force of safety experts in Pakistan to review in depth any available safety standards from other countries and companies, including those in the Appendices to this report and recommend a set of safety standards that would be appropriate for Pakistan.

RAM Standards

49. NEPRA must decide if it will a) require the plants to input the basic RAM data necessary to calculate the three RAM indicators or b) require the plants to perform the calculations themselves and simply input the resulting values to NEPRA. If NEPRA decides on option (a), it will have to develop a process for collecting and compiling the data necessary to calculate the three RAM Key Performance Indicators (definitions are found in the RAM Standards section of this report). These options include 1) creating simple input spreadsheets 2) waiting a few months for the World Energy Council to finalize its data collection process or 3) adopting the international GADS data system. While each of these options have pros and cons it is recommended that NEPRA start with option (1) immediately while reviewing in depth options (2) and (3) for the long-term. If NEPRA chooses option (b), NEPRA would only have to develop a consistent KPI input spreadsheet and methods for summarizing and publishing the results. Although this appears to be a simple solution, there is some risk in not having the basic data that goes into the KPI calculations. In addition, compiling accurate averages of the KPI Energy Loss Rate (ELR) for a group of units with different Service Hours is not possible unless that basic data is known. A reasonable alternative might be for NEPRA to develop uniform calculation spreadsheets for all plants to use where the basic data plus the resulting KPI calculations are input to NEPRA.

50. Depending on which option is chosen, NEPRA should require the plants to input this data monthly, along with quarterly and annual summaries.
51. NEPRA should then compare the actual RAM performance against the distribution of RAM performance by their peers, as given in Appendix YYY or as contained in the NERC-GADS database and accessed using NERC’s benchmarking software program, pc-GAR (for information on pc-GAR go to www.nerc.com and select “GADS Services” on the NERC Fast Links pull-down screen. Other GADS information can also be found on this site).

52. NEPRA should then set the RAM standards (long-term and short-term) based on the gap between the plant’s current RAM performance and the distribution of RAM performance of each unit’s peer group.

53. NEPRA should consider creating incentives for plants to achieve RAM performance better that the standards that are proportional to the actual value created as a result of that better performance. This will require a study to estimate that value (see section 8).

**Efficiency Standards**

54. NEPRA should investigate to determine if a heat rate testing program currently exists in Pakistan whose data could be used to determine each unit’s “deviation from theoretical best achievable” heat rate. If such data does not exist, NEPRA must decide if developing such a program would be cost-effective.

55. Assuming that the necessary efficiency data can be obtained, NEPRA must then estimate for each unit the percentage deviation from the “theoretical best achievable heat rate” that would be cost effective (generally somewhere in the range of 2-4% is what many companies around the world have as their internal standard).

**Cost Standards**

56. NEPRA should assign one of its staff to investigate the possibility of joining the international arm of the EUCG, a not-for-profit industry organization whose major focus is compiling and sharing cost data and cost benchmarking. Future directions for developing cost standards for Pakistan can then be determined based on the insight gained from participation in this organization’s activities.
VII. Market-Based Indicators

57. For regulated electric generating companies the indicators described in the preceding sections have worked reasonably well for decades, especially for base-loaded generating plants. However, in recent years the increased reliance on peaking plants (especially simple-cycle Gas Turbines) to meet the demand has led to the realization that these indicators are not completely adequate. After much discussion, the IEEE has modified IEEE Standard 762 – Standards Definitions for use in reporting Electric Generating Unit Reliability, Availability and Productivity to include a new indicator called Equivalent Forced Outage Rate during demand periods (EFORd). This would be similar to the Energy Loss Rate if it were only measured during demand periods. Using EFORd instead of monthly or annual averages has led plant management to become more pro-active in developing an anticipatory mind-set of its staff since it will only benefit if it is available when it is needed. This has resulted in plants being more reliable during peak seasons, peak days and peak hours with large financial savings (Ref 8).

58. EFORd attempts to measure the ability of the generating unit to produce its rated capacity during the times it would actually have been dispatched! During other times it would not be credited if it were available or penalized if it were not available. A further refinement that many companies in true market environments have created is called Commercial Availability (CA). This takes EFORd and “weights” it in proportion the actual value the plant gained or lost during demand periods when it was available or unavailable. Although IEEE has not yet incorporated CA into its standard, many companies have begun using it since it links directly the plants RAM performance to the overall bottom line (Ref 9).

59. Another aspect of performance indicators is the increasing recognition that being at top performance of all KPIs is neither feasible nor cost-effective. Rather it is the integration of all KPIs, including RAM and Cost (plus safety, environmental, quality, etc.) into a set of performance results that will lead to the Optimum Economic Performance of the plants (Ref 1 and Ref 10).

60. The World Energy Council’s (WEC) Performance of Generating Plant (PGP) Committee has been monitoring the effects of the global trend to more bottom-line performance metrics. Pakistan and NEPRA should stay aware of these major trends by either active participation on the WEC’s PGP Committee through its WEC national committee or by reviewing publications of the PGP.

61. For renewable technologies (solar, wind, geothermal, etc.) the WEC has established a Working Group that is currently well down the path for creating performance metrics for these technologies. It is recommended that NEPRA and other stakeholders in Pakistan with an interest in these technologies monitor and/or contribute to this Working Group’s activities.
VIII Recommendations for Future Development

62. Incentives – To achieve their intended goal incentives should be a percentage of the actual value created as a result of plant performance improvement. For example if availability is increased, but only at times when the unit’s generation is not needed then it has created no value. The ability to accurately forecast that value is vital to the establishment of an appropriate incentive program. In some companies these value forecasts are made using expansion planning and production cost computer models using techniques as briefly described below:

a. Energy Loss Rate (ELR) – When a low cost unit experiences a failure resulting in a partial or full outage, a higher cost unit must operate to make up the lost load. There is a real savings if low cost units fail less frequently or can be returned to service more quickly (ELR measures the probability of a unit being unable to generate at its dependable capacity). Production cost simulation computer programs are used to predict the marginal cost of generation for each future hour, using approved estimates of load growth, fuel costs, system demand, ELR and Planned Outage Factors and efficiencies for all system units plus numerous other factors. Since these factors often have a great deal of uncertainty, probabilistic methods are employed. The value of improving the ELR of any specific unit is predicted by subtracting its variable cost rate from the system marginal cost in each hour (if the system’s predicted marginal cost is less than the unit’s variable cost rate, the unit is assumed to not be dispatched and the value is zero for that hour). Hourly savings are summed for the year and multiplied by the unit’s net dependable capacity, then multiplied by 0.01 to get the value for a one percent change in ELR. In addition the value of deferred new plant construction resulting from an improvement in a unit’s ELR is added to the above production cost savings (for example a 1 percent improvement in ELR of a 100MW unit means a deferral of approximately 1 MW and that value can be quantified).

b. Planned Outage Factor (POF) – The method for estimating the value of a one percent change in a unit’s POF is similar to that for ELR but is confined to the maintenance overhaul season (typically times other than the peak season).

c. Heat Rate – This calculation method is less complex than that for ELR of POF since it only depends on the amount of energy the unit is expected to generate and the unit’s fuel cost.

d. Auxiliary Power Consumption – When a unit’s auxiliary power requirements are reduced its net output is increased with no increase in operating costs and the output of the unit operating at the system’s marginal cost is reduced by that amount. Therefore, the value of reducing auxiliary power consumption is the total marginal cost at that hour when the unit is forecast to operate for each MW reduction.

e. Capacity Improvement – When the dependable capacity of a unit is increased there is a proportional increase in input (fuel plus variable O&M) and so is much less valuable that for a similar increase in net dependable increase resulting from an auxiliary power consumption decrease in that the auxiliary power decrease is “free” energy (no additional input required for the extra output).
63. It is strongly recommended that a study be undertaken to forecast the value of improvement in the above performance indicators for Pakistan’s public sector power plants. Other successful improvement programs have clearly demonstrated that establishing and communicating these values to all stakeholders, especially plant staff, and linking incentives to these values is one of the most vital elements in any improvement initiative.

64. Another important recommendation for the future is for NEPRA to ensure that the data collected can be accessed and applied by the stakeholders in their efforts to quantify the cause-effect relationship of past performance so that it can be applied to future decisions. The consultant believes that setting performance standards can establish the appropriate goals from a top-down perspective. However, sustainable performance improvement is achieved only from the bottom-up, when individuals make better day-to-day decisions. Having access to high quality data will help enable them to make those better decisions. The case study in Appendix 8 gives a detailed description on how high performance generators around the world have used performance data in improving their plant’s performance.
References

1. Richwine, Robert R.; Maximizing Availability May Not Optimize Plant Economics; Power Magazine; September, 2004

   The following case studies are published on the World Energy Council’s webpage at www.worldenergy.org/forward.asp?page=pgp for the months indicated.


4. Performance Data to Performance Improvement – Answering the $80 Billion per Year Question; Jan., Feb., March, April 2003.


6. An Application of Benchmarking to ESKOM’s 90:7:3 Programme; April, 2002.


8. Peak Season Reliability; March 2002.


Appendix-1

GENERATION PERFORMANCE STANDARDS

Terms of Reference (TOR)

Background
1. The Government of Pakistan (GoP) is pursuing the power sector reform policy to steer it towards an efficient, competitive and market driven sector. Key elements envisaged in the reforms are:
   a. Establishing an independent regulatory agency (National Electric Power Regulatory Authority)
   b. Unbundling and restructuring of WAPDA into independent companies/entities providing generation, transmission and distribution services
   c. Improving the operational and financial performance of the new entities/companies.
   d. Promoting greater private sector participation in the sector through both gradual privatization of the state owned entities and assets; and attracting private investment in the sector.

2. NEPRA was established under the Regulation of Generation, Transmission and Distribution of Electric Power Act (XL of 1997)-The NEPRA Act. The Authority (NEPRA) is mandated to perform the following functions under the Act:
   a. Grant licenses to companies engaged in the provision of electricity generation, transmission or distribution services.
   b. Determine tariff, rates, charges and other terms and conditions for the supply of electric power services.
   c. Prescribe and enforce performance standards, and investment standards.
   d. Prescribe fees for grant of licenses and fines for contravention of the Act.
   e. Establish a Uniform System of Accounts.
   f. Ensure continuous and efficient supply of electric power services to the consumers by utilities.

3. Pursuant to the above objectives, the following Rules, Regulations, Procedures, Codes, and Documents have been approved and/or prescribed:
   e. Licensing (Generation) Rules, 2000.
   g. Consumer Eligibility Criteria (Regulations), 2003.
h. Resolution of Disputes between IPPs and other Licensees, 2003.
k. Grid Code.
l. Distribution Code.

4. According to Section 34, and Section 7(2)(c) of NEPRA Act, the Authority has been mandated to prescribe Performance Standards for generation, transmission and distribution companies which are licensees of NEPRA. The prescription of these standards is to be accomplished in the form of notified rules from the GoP as per Section 46(k) of NEPRA Act.

5. Associated NEPRA regulatory framework with respect to Generation Performance Standards, which have been approved so far, are as follows:
   b. NEPRA Generation Licenses.
   c. Grid Code.

6. ADB Consultants (British Power Inc) inducted for NEPRA capacity building program have also provided some input with respect to prescription of Generation Performance Standards by NEPRA.

**Market Structure**

7. A Central Power Procurement Agency (CPPA) has been established within NTDC, which will be responsible for the purchase of wholesale electricity from generation companies including existing as well as future IPPs, dispatch, and financial settlement. NEPRA has issued a License to NTDC with a market structure based on a “Single Buyer Plus” Model during transition wherein July 1, 2009 has been set as the date of introduction of the Wholesale Power Market. Accordingly, any bulk power consumer or a distribution company will be permitted to enter into a bi-lateral long-term electricity purchase agreement with any power producer of its choice.

**Power Generation Scenario**

8. Installed power generation capacity in the country has been divided up between two systems i.e. WAPDA and KESC. Table-1 provides an overview of the generation composition for each system for the year ending 2003.

   **Table-1: Installed Generation Capacity**

<table>
<thead>
<tr>
<th></th>
<th>Hydel (Public)</th>
<th>Thermal (Public)</th>
<th>Hydel (Private)</th>
<th>Thermal (Private)</th>
<th>Nuclear</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>WAPDA</td>
<td>5,009</td>
<td>4,740</td>
<td>30</td>
<td>5,715</td>
<td>325</td>
<td>15,819</td>
</tr>
<tr>
<td>KESC</td>
<td>1,756</td>
<td>1,756</td>
<td>262</td>
<td>137</td>
<td></td>
<td>2,155</td>
</tr>
</tbody>
</table>

Source: Energy Year Book, 2004

9. The details of generation capacity can also be summarized as follows:
a. Nuclear 3%
b. WAPDA Hydel 28%
c. WAPDA Thermal 26%
d. WAPDA IPPs 32%
e. KESC Thermal 10%
f. KESC IPPs 1%
g. Total Installed Generation Capacity = 17,975 MW
h. Total Available Generation Capacity (Annual Average) (74% Hydro, 85% Thermal, 78% Nuclear) = 14,689 MW
i. Total Maximum Demand (2003) = 13,017 MW

10. The generation companies are under an obligation under NEPRA licenses to ensure provision of safe, efficient and reliable electric power at least cost, for delivery to NTDC for onward delivery and sale to distribution companies and Bulk Power Consumers (BPCs).

11. NEPRA regulatory framework with respect to Quality of Service (QoS) is a new mechanism and protocol, through which QoS offered by the generation, transmission and distribution licensees to its consumers shall be ensured. The QoS deals with the areas of system security, reliability, adequacy, quality of supply, accessibility, and availability of supply, services, and facilities involved in the production, delivery and sale of electric power. The new regulatory regime presents challenging environment where QoS standards have to be enforced.

12. The issue and scope of Generation Performance Standards depends on the power market structure, and degree to which generation has been de-regulated, and if it is competitive in the country or not. For the power sector where generation is going through transition leading to a competitive market, there is a need for certain performance criteria through which performance concerns can be appropriately addressed. Certainly, areas such as generation reliability/availability, dependable power capacity and energy delivery, fuel efficiency and heat rates, auxiliary consumption, and generation unit constraints need to be closely watched in one form or another. Present power sector environment in the country is far from being an ideal situation to expect that market forces would become the prime-mover of generation efficiency, reliability and availability. Therefore, the generation business cannot be left on its own to ensure its optimal performance. Some regulatory intervention is required to ensure post-restructuring concerns.

13. Key challenges with respect to the prescription of Generation Performance Standards are: 1) non-availability of credible data from the utilities to assess the ground situation with respect to the status of presently installed generating plants as to how far the deviations are from the design standards; 2) analysis of the data to recommend technical and financial solutions to conform to the established technical standards (cost, and no-cost solutions).

14. The efficiency improvements required through enforcement of Generation Performance Standards should be gradually achieved overtime such that it does not lead to huge investment requirements and dramatic rate shocks to the consumers.
Objectives and Purpose of the Study
15. The study is geared towards followings aims and objectives:
   a. Identify and establish the generation performance indicators from a regulator’s perspective, specifically in the areas of reliability, availability, efficiency, and safety of electric power delivery.
   b. Collecting data on generator performance indicators (as identified under ‘a’) technology-wise, in Pakistan, and from other countries in the region / outside the region.
   c. Assist NEPRA in prescribing the performance / technical standards (ranges) for regulated generation entities against the collected data (as collected under ‘b’), and to enable it to develop appropriate Rules on Generation Performance Standards.
   d. Provide specific formats for obtaining required information from all generation licensees for use by NEPRA during the periodic process of performance monitoring and compliance.

16. Writing down detailed technical specifications for the generators is not required. Broad-based generation performance indicators / benchmarks need to be established first, which is expected to lead to the improvement of technical standards of the generation companies; and collection of quantitative and verifiable data is expected to provide a clear understanding of operating conditions of the existing generating units on the system.

17. Together with the review of broad-based performance indicators / benchmarks prescribed in the form of notified Rules in the first instance, NEPRA would gradually and progressively prescribe and enforce improved Generation Performance Standards over successive regimes.

18. Very little national / international expertise, or international published material, is available to NEPRA at this time to provide guidance on generation performance standards. This Study is envisaged to pave the way for definition of quantitative and verifiable performance standards consistent with the existing situation, so as to facilitate continuing improvement in the generation sub-sector.

Scope of Work
19. The scope of work for the Consultant is outlined as follows:
   a. Review of the existing situation in power sector in general and the generation sub-sector in particular, from a regulator’s perspective specifically in the areas of reliability, availability, efficiency, and safety of electric power delivery.
   b. Definition of the performance indicators for the generators, which are important from a regulatory perspective. This activity would inter alia include:
      i) Indicators with respect to obligation of power delivery to NTDC as per NEPRA’s approved regulatory framework.
      ii) Indicators relating to improvement in operating efficiency and lower production costs in the generation sub-sector.
      iii) Indicators to facilitate and foster competitive power markets, envisaged from July 2009.
c. Assessment of the current state of installed public sector and private generators in Pakistan. This work may *inter alia* include:
   i) Desk review of selected IPP contracts and data on operating performance.
   ii) Field visits to GENCOs (Ex-WAPDA, public sector generation companies).
   iii) Interaction with the stakeholders, and retrieval of requisite information.

d. Collection of information / benchmarks on performance indicators from other comparable utilities in the region, and internationally, to provide a basis for comparison. This activity is envisaged through available published material and Consultant’s in-house data sources.

e. Recommendation on performance indicators and technical standards (appropriate ranges) covering the areas of operation dealing with reliability, availability, efficiency, and safety of the generating plants with *inter alia* following considerations:
   i) Performance indicators (technology-wise) need to be few in number but best represent the overall performance of the generating units.
   ii) Performance indicators which are measurable, quantifiable and controllable by the licensees; and enforceable by the regulator.
   iii) Prescribed formats for the generating stations for collecting information on recommended performance indicators.
   iv) Technical standards, which need improvements in the future.

**Responsibilities**

20. The Consultant shall be *inter alia* responsible for the following:
   a. Study the approved NEPRA regulatory framework with respect to performance monitoring and compliance.
   b. Study selected IPP contracts with respect to the generating plants obligations to meet certain performance standards.
   c. Study the present power generation sub-sector in the Pakistan, in the context of delivered cost of electricity supplies to the end-consumers.
   d. Review international / regional position on performance indicators (technology-wise) for comparison purposes to support study recommendations.
   e. Discussions/meetings with NEPRA professionals and other concerned stakeholders.
   f. Formulation of recommendations in the form of a comprehensive report; dissemination of report to NEPRA professionals; and presentation before the NEPRA and other stakeholders.

**Deliverables**

21. The following deliverables shall be required before the completion of the assignment:
   a. Inception report defining the methodology for the proposed work and review of NEPRA’s existing regulation, and its responsibilities.
   b. Draft final report providing performance indicators and recommendations on the technical standards, for review and comments by NEPRA.
   c. Final report (after incorporating NEPRA comments on the draft report).
Appendix-2

Illustrative Power Quality Standards

1. Information from Pakistan:
A 1995 power purchase document for Pakistan the consultant was given access to, lists the following Power Quality standards that are tested and their allowable ranges (Schedule 4; p 4-2):

Automatic Voltage Regulator (AVR) Droop

“The AVR will be demonstrated to control the generator voltage over the range of plus or minus 10 percent of rated voltage with a droop characteristic of plus or minus 0.5 percent.”

Turbine Governor Operation

“The operation of each turbine speed governor will be demonstrated over its range, the droop being adjusted from 95 percent to 105 percent.”

Reactive Capacity

“Tests will demonstrate the capability of the Complex to operate at rated voltage and frequency at power factors and under reactive conditions as follows:

Combustion Turbine Generators:
100% output 0.95 Leading Power Factor
100% output 0.85 Lagging Power Factor
0% output 54 MVAR Leading Power Factor
0% output 118 MVAR Lagging Power Factor

Steam Turbine Generator
100% output 0.95 Leading Power Factor
100% output 0.85 Lagging Power Factor
0% output 100 MVAR Leading Power Factor
0% output 190 MVAR Lagging Power Factor

Schedule 2 of the 1995 PPA (p2-4) lists the following standards for technical limits:

Reactive Power

Same as above

Voltage

The Generators can operate within the range of plus or minus 10.0% on the 220kV high voltage system which range shall not be exceeded.
Frequency

The Complex can operate continuously within the frequency range of 48.5 Hertz to 51.5 Hertz at the rated voltage of 220kV. The turbine-generators shall be subject to cumulative off-frequency time limits as follows:

<table>
<thead>
<tr>
<th>Under Frequency</th>
<th>Over Frequency</th>
<th>Cumulative Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>-1.5 to -3.0 Hz</td>
<td>+1.5 to +2.0 Hz</td>
<td>90 minutes</td>
</tr>
<tr>
<td>-3.0 to -3.5 Hz</td>
<td>+2.0 to +2.5 Hz</td>
<td>12 minutes</td>
</tr>
<tr>
<td>-3.5 to -4.0 Hz</td>
<td>+2.5 to +3.0 Hz</td>
<td>1 minute</td>
</tr>
</tbody>
</table>

Droop

The Unit governor droop is adjustable in the range 95% to 105%. The automatic voltage regulator droop setting is adjustable in the range of plus or minus 0.5% of rated voltage.

2. Information from other companies:

REACTIVE POLICY
FOR GENERATION FACILITIES CONNECTING TO THE SOUTHERN COMPANY TRANSMISSION SYSTEM

October 22, 1999

INTRODUCTION

Reactive power from generators is necessary to maintain the reliability of the transmission system. NERC Planning Standards (Measurement I.D.M2) require that "Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability." The Southern Company has analyzed the need for reactive power from generators connected to the transmission system to maintain reliability. As a result of this analysis, a reactive policy has been developed. This policy outlines the amount of reactive power capability required from generating facilities connected to the Southern Company transmission system.

POLICY

1. Minimum Acceptable Reactive Requirements

At continuous, rated MW output (for summer peak conditions), calculations must show that the generator's facility shall have the capability of supplying at least 0.33 Mvars (dynamic
vars) into the transmission system for each MW supplied into the interconnection point when the transmission system bus voltage at the interconnection point is at the specified test voltage. See Appendix A for definitions of continuous rated MW output. The specified test voltages are as follows:

<table>
<thead>
<tr>
<th>Voltage Range</th>
<th>Test Voltage (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>From 44 kV through 161 kV</td>
<td>1.00</td>
</tr>
<tr>
<td>230 kV connected units</td>
<td>1.01</td>
</tr>
<tr>
<td>500 kV connected units</td>
<td>1.02</td>
</tr>
</tbody>
</table>

The facility shall also be capable (at continuous, rated MW output) of absorbing 0.23 Mvars from the transmission system for each MW supplied into the transmission system bus when the transmission system bus is at the following:

<table>
<thead>
<tr>
<th>Voltage Range</th>
<th>Test Voltage (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>From 44 kV through 161 kV</td>
<td>1.03</td>
</tr>
<tr>
<td>230 kV connected units</td>
<td>1.04</td>
</tr>
<tr>
<td>500 kV connected units</td>
<td>1.05</td>
</tr>
</tbody>
</table>

Peaking generation may be exempted from the MVAR absorption requirement on a case by case basis. This could include simple cycle combustion turbines and other units that would typically be dispatched only during peak load periods.

The required calculations listed above must take into account the allowable range of generator bus voltages considering possible station service load fed from the generator bus. They must also take into account the tap that the GSU will be set on. It is intended that the generating units meet both the var production and var absorption requirements on the same GSU tap. For GSU’s which do not have a test report available, the manufacturing tolerance for the impedance should be taken into account in the calculations.

2. **Operation and Voltage Schedule**

When a generator is delivering power to the Southern Company transmission system, the generator owner shall operate its generation to meet the voltage schedule provided to it as measured at the interconnection point between the transmission system and the generator's facilities. If the scheduled voltage is not maintained, the following two criteria will be reviewed:

(a) If system conditions occur which prevent the generator from maintaining voltage schedule but the generator is maximizing its MVAR output (greater than or equal to $0.33 \times \text{rated MW}$), then that is considered acceptable performance. If that maximum reactive output is less than $0.33 \times \text{rated MW}$, then the generator will have to explain the Mvar deficiency to the transmission provider/operator. If it is determined that the generator is not in compliance, penalties could be imposed. It is realized that this desired Mvar output value may not be achievable under all system conditions and generator loading conditions.

(b) If system conditions occur which prevent the generator from maintaining voltage schedule but the generator is maximizing its MVAR absorption (greater than or equal to $0.23 \times \text{rated MW}$), then that is considered acceptable performance. If that
maximum reactive absorption is less than $0.23 \times \text{rated MW}$, then the generator will have to explain the deficiency to the transmission provider/operator. If it is determined that the generator is not in compliance, penalties could be imposed. It is realized that this desired Mvar output value may not be achievable under all system conditions and generator loading conditions.

It is possible that the transmission provider will request the generator to operate on a GSU tap which will make the reactive range of the generator different from a production value of $0.33 \times \text{rated MW}$ and an absorption value of $0.23 \times \text{rated MW}$. When this happens, the values in items (a) and (b) above will be adjusted accordingly by the transmission provider/operator.

When a generating unit is on-line, the full reactive capacity of the unit is expected to be available to the transmission system whether it is generating at reduced MW or at continuous rated MW. If the generating unit is temporarily operating above continuous rated MW, it must reduce to the continuous rated MW level when requested by the transmission system operator if that is necessary for the unit to produce the amount of Mvars required by this policy. Generators which have their reactive capability limited by an equipment failure or operating problem should correct the situation as soon as feasible.

An exception to the requirement of holding a scheduled voltage on the transmission grid may be given to co-generation facilities which have significant customer load served from the generator bus. These type facilities will be evaluated on a case-by-case basis.

3. **Penalty for Not Fulfilling Above Requirements**

It is expected that any new generation facilities or existing units seeking to upgrade their MW capacity comply with these reactive requirements. If the generating facilities do not comply, this will be considered a violation of the interconnection agreement and appropriate action will be taken. This action could range from an economic penalty up to possible disconnection. The economic penalty would be an equivalent dollar amount for an equivalent dynamic Mvar-producing device on the transmission system – a STATCOM or a static var compensator.

The generator has the option to run at reduced MW output to comply with the reactive output requirement. There will be no compensation from the transmission system to the generator for having to reduce MW to comply with the reactive output requirement. Also, there will be no compensation from the transmission system to the generator for having a reactive capability which exceeds the requirements of this policy.

4. **Applicability of This Reactive Policy**

The policy applies only to rotating, synchronous generators greater than 1 MW connected to the transmission grid (44 kV and above). This reactive policy applies to all new generation facilities connecting to the Southern Company transmission system. Existing units are expected to maintain their existing reactive capability and do not have to comply with the reactive capacity requirements of this policy until they attempt to upgrade their MW capacity. An exception to this general policy may be hydro units seeking to upgrade.
Because the upgrading of hydro units is done to make more efficient utilization of a limited water resource, these upgrades may be treated on a case-by-case basis as to what the reactive requirement will be. The policy will become effective 1/1/2000. This will give all parties sufficient time to become informed on the issues and to allow new generators that will be announcing sitings after 1/1/2000 to have sufficient time to design the GSU and the generator to meet these requirements. It is realized that some generator owners may already have purchased major equipment for their project. Therefore, exceptions to this reactive policy will be given as follows:

Any generator that will reach commercial operation before 1/1/2003 and (1) can show firm evidence that major equipment, such as the turbine-generator and GSU, has been procured or (2) has committed to a firm power contract price prior to 1/1/2000, is not strictly bound by these reactive requirements.

However, it is the intent of these requirements that the generation facility must make every effort to provide var support up to the capability of the equipment when attempting to hold scheduled voltage. Moreover, the generator owner shall diligently work with the transmission system owner (or operator) to maximize the reactive capability of the equipment including redesign or specifications of equipment not yet procured. Finally all generators reaching commercial operation after 1/1/2003 must comply with this reactive policy.

For existing units seeking to upgrade their MW capacity and which currently have reactive capability above 0.33 Mvars/MW, the reactive requirement becomes 0.33 Mvars/MW times the new MW capability of the unit. For existing units seeking to upgrade their MW capacity and which currently have reactive capability below 0.33 Mvars/MW, the requirement will be the sum of their existing net Mvar capability plus 0.33 times the amount of MW increase.

For example, suppose a 500 MW existing unit can provide 300 MVAR net to the transmission system, or 0.60 MVAR/MW. A project of increasing its rated MW to 600 MW has been considered. The new Mvar requirement will become 200 Mvars (.33 times 600 MW). For another example, suppose a 500 MW existing unit can provide only 100 MVAR net to the transmission system, or 0.20 MVAR/MW. A project of increasing its rated MW to 600 MW has been considered. The new Mvar requirement will become 133 Mvars (100 Mvars existing plus 0.33 times 100 MW).

Steam turbine upgrades of existing units which will be completed prior to 1/1/2003 and for which a contract is already in place will be exempted from this policy. As mentioned previously, hydro units seeking to upgrade will be treated on a case-by-case basis and may not be required to meet the reactive capability requirements of this document.
Definition of Generator Continuous Rated MW Output

The purpose of this appendix is to define the term "continuous rated MW output" for the various generator types. All resources connected to the Southern Control Area are required to comply with NERC and SERC schedules and criteria for demonstrating generator MW capability.

1. Coal, nuclear, oil and gas facilities: These electric generating unit types are turbine-generators which have steam power as their prime mover. Their "Continuous Rated MW Output" shall be the generating unit's full load MW capability expected to be available continuously on a daily basis under normal operating conditions during June - August, when all units of this type residing at the plant are demonstrating concurrently.

2. Combustion turbine and combined cycle facilities: These electric generating unit types are turbine-generators which have fuel/air mixtures expanded through combustion as their primary prime mover and, in the case of combined cycle facilities, exhaust heat recovery steam generation as their secondary prime mover. Their "Continuous Rated MW Output" shall be the generating unit's full MW capability expected to be available continuously on a daily basis under normal operating conditions during June - August, when all units of this type residing at the plant are demonstrating concurrently.

3. Conventional and pumped storage hydro facilities: These electric generating unit types are turbine driven generators which have hydro power as their prime mover. Their "Continuous Rated MW Output" shall be the generating unit's full load efficient gate MW capability expected to be available continuously for 8 hours during five continuous weekdays of the June - August peak season, when all units of this type residing at the plant are demonstrated concurrently. Simulated operation using an acceptable hydro production modeling program which utilizes at least 30 years of hydro flow data may be used in the demonstrated rating process.
Appendix-3

Illustrative Environmental Standards

The Pakistan Environmental Protection Agency’s (PEPA) website with links to the National Environmental Quality Standards (NEQS) should be used to set these standards. The tables in the attached Acrobat file are taken from the NEQS.

Annex I (amended)

NATIONAL ENVIRONMENTAL QUALITY STANDARDS FOR MUNICIPAL AND LIQUID INDUSTRIAL EFFLUENTS (mg/l, UNLESS OTHERWISE DEFINED)

<table>
<thead>
<tr>
<th>S.No.</th>
<th>Parameter</th>
<th>Existing Standards</th>
<th>Revised Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Into Inland Waters</td>
<td>Into Sewage Treatment</td>
</tr>
<tr>
<td>1.</td>
<td>Temperature or Temperature Increase*</td>
<td>40°C</td>
<td>=&lt;30°C</td>
</tr>
<tr>
<td>2.</td>
<td>pH value</td>
<td>6-10</td>
<td>6-9</td>
</tr>
<tr>
<td>3.</td>
<td>Biochemical Oxygen Demand (BOD) &lt; sub&gt;3&lt;/sub&gt; at 20°C&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td>4.</td>
<td>Chemical Oxygen Demand (COD) &lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>5.</td>
<td>Total suspended solids (TSS)</td>
<td>150</td>
<td>200</td>
</tr>
<tr>
<td>6.</td>
<td>Total dissolved solids (TDS)</td>
<td>3500</td>
<td>3500</td>
</tr>
<tr>
<td>7.</td>
<td>Grease and oil</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>8.</td>
<td>Phenolic compounds (as phenol)</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>9.</td>
<td>Chloride (as Cl&lt;sup&gt;-&lt;/sup&gt;)</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>10.</td>
<td>Fluoride (as F&lt;sup&gt;-&lt;/sup&gt;)</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>11.</td>
<td>Cyanide (as CN&lt;sup&gt;-&lt;/sup&gt;) total</td>
<td>2</td>
<td>1.0</td>
</tr>
<tr>
<td>12.</td>
<td>Anionic detergents (as MBAs) &lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>13.</td>
<td>Sulphate (SO&lt;sub&gt;4&lt;/sub&gt; &lt;sup&gt;-&lt;/sup&gt;)</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>14.</td>
<td>Sulphide (S&lt;sup&gt;-&lt;/sup&gt;)</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>15.</td>
<td>Ammonia (NH&lt;sub&gt;3&lt;/sub&gt;)</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>16.</td>
<td>Pesticides &lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>0.15</td>
<td>0.15</td>
</tr>
</tbody>
</table>
NATIONAL ENVIRONMENTAL QUALITY STANDARDS FOR INDUSTRIAL GASEOUS EMISSION (mg/Nm³, UNLESS OTHERWISE DEFINED)

<table>
<thead>
<tr>
<th>S.No.</th>
<th>Parameter</th>
<th>Source Of Emission</th>
<th>Existing Standards</th>
<th>Revised Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Smoke</td>
<td>Smoke opacity not to exceed</td>
<td>40% or 2 Ringlemann Scale</td>
<td>40% or 2 Ringlemann Scale or equivalent smoke number</td>
</tr>
<tr>
<td>2.</td>
<td>Particulate matter (1)</td>
<td>(a) Boilers and furnaces:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(i) Oil fired</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(ii) Coal fired</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(iii) Cement Kilns</td>
<td>200</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Grinding, crushing, clinker coolers and related processes, metallurgical processes, converters, blast furnaces and cupolas</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>3.</td>
<td>Hydrogen Chloride</td>
<td>Any</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>4.</td>
<td>Chlorine</td>
<td>Any</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>5.</td>
<td>Hydrogen fluoride</td>
<td>Any</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>6.</td>
<td>Hydrogen sulphide</td>
<td>Any</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>7.</td>
<td>Sulphur Oxides (2)(3)</td>
<td>Sulfuric acid/Sulphonic acid plants</td>
<td>400</td>
<td>5000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Other Plants except power</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Plants operating on oil and coal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8.</td>
<td>Carbon Monoxide</td>
<td>Any</td>
<td>800</td>
<td>800</td>
</tr>
<tr>
<td>9.</td>
<td>Lead</td>
<td>Any</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>10.</td>
<td>Mercury</td>
<td>Any</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>11.</td>
<td>Cadmium</td>
<td>Any</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>12.</td>
<td>Arsenic</td>
<td>Any</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>13.</td>
<td>Copper</td>
<td>Any</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>14.</td>
<td>Antimony</td>
<td>Any</td>
<td>20</td>
<td>20</td>
</tr>
</tbody>
</table>
Appendix-4

RAM Indicators - Peer Group Ranges

The following tables give important statistical points within the distribution of the 5 year averages of the key RAM indicators for units in the NERC database that were judged to comparable to Pakistan’s power plants. The distributions were developed from the NERC benchmarking software pc-GAR. These distributions can be used to set ranges for standards of the three recommended RAM indicators.

Determining the best peer select criteria for any particular generating unit is not as simple as defining the technology, size and fuel type. Other factors such as operating regime (demand) or vintage have been statistically proven to be much more important in selecting a peer group for comparisons and benchmarking. References 1,2 & 3 discuss this subject in more detail. Due to the time and cost limitations of this project, it was decided to rely on the consultant’s extensive experience in this field to determine the best peer group for each Pakistan plant. Future enhancements to this process might include a more statistically accurate analysis to select peer units with as close a match as possible to the Pakistan’s units’ design & mode of operation characteristics but balanced with the need to have enough units in the peer group for statistical validity with a minimum of 30 units recommended.

The following tables show the values for each RAM KPI for the 10th, 25th, 50th, 75th, and 90th percentiles of the distribution as well as the mean (average) value. For EAF, a high value is best, while for ELR and POF, low value is best. Where Pakistan plant data for these KPIs was provided a comparison was made.

**GROUP 1 – Small Fossil Steam Units**

**Select Criteria:** 50MW – 199MW; oil/gas fuel; Capacity Factor greater than 35%. There were 45 units in this peer group.

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>KPI</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>73.74</td>
<td>85.24</td>
<td>88.76</td>
<td>87.41</td>
<td>92.62</td>
<td>95.69</td>
</tr>
<tr>
<td>ELR</td>
<td>1.75</td>
<td>2.71</td>
<td>5.74</td>
<td>4.84</td>
<td>8.71</td>
<td>13.46</td>
</tr>
<tr>
<td>POF</td>
<td>0.25</td>
<td>3.08</td>
<td>5.43</td>
<td>7.29</td>
<td>7.34</td>
<td>17.68</td>
</tr>
</tbody>
</table>
Pakistan’s Saba unit (136MW) is in this category and provided a value for its Availability Factor (AF) from 1 Jan. 2000 to 13 April 2006 of 84.43%. The AF is similar to the EAF KPI except that it does not incorporate the effects of planned or unplanned deratings. Therefore, a direct comparison to the peer group data in Table 1 could not be made. In order to make a direct comparison, the consultant was able to extract the AF from the peer group data contained in the NERC-GADS database. Saba’s value of 84.43% puts it at the 38th percentile of its peers in North America. Based on the information provided, it would appear that there is a distinct opportunity for Saba to improve its RAM performance although other KPI data is needed as well as the trend of that data to give a definitive opinion.

Multan is also in this category (2 X 65 MW steam turbines) and provided an AF value for 2005 that averaged 57.65%, putting it below the 10th percentile and indicating a strong potential for substantial improvement.

Faisalabad has steam turbines whose AF for 2005 averaged 73.98 putting it just above the 10th percentile, indicating substantial potential for improvement.

**GROUP 2 – Large Fossil Steam Units**

**Select Criteria:** 200MW – 600MW; oil/gas fuel; Capacity Factor greater than 35%. There were 57 units in this peer group.

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>74.09</td>
<td>81.40</td>
<td>85.52</td>
<td>83.55</td>
<td>89.59</td>
<td>92.25</td>
</tr>
<tr>
<td>ELR</td>
<td>3.09</td>
<td>5.92</td>
<td>8.11</td>
<td>8.57</td>
<td>11.34</td>
<td>14.29</td>
</tr>
<tr>
<td>POF</td>
<td>0.0</td>
<td>4.40</td>
<td>7.52</td>
<td>8.96</td>
<td>11.22</td>
<td>14.51</td>
</tr>
</tbody>
</table>

Muzaffargarh has several steam turbines in this category with an average Availability Factor for 2005 of 75.68%, putting it slightly better than the 10th percentile and indicating substantial potential for improvement. The HUBCO plant also falls into this category. Its AF of 82.5% for 2005 puts it at the 22nd percentile, suggesting potential for improvement, although as an IPP the terms of its PPA contract may not adequately incentivize it to do so.

Pak Gen and Lal Pir units also fall into this category. No RAM KPI data is currently available from those two plants.
GROUP 3 – Smaller Combined Cycle Units

Select Criteria: 50MW – 199MW. There were 66 units in this peer group.

Table 3

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>74.25</td>
<td>81.85</td>
<td>85.78</td>
<td>84.77</td>
<td>92.89</td>
<td>95.95</td>
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<tr>
<td>ELR</td>
<td>2.57</td>
<td>5.27</td>
<td>10.10</td>
<td>13.13</td>
<td>18.01</td>
<td>29.38</td>
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<tr>
<td>POF</td>
<td>0.0</td>
<td>1.13</td>
<td>4.93</td>
<td>6.86</td>
<td>8.82</td>
<td>14.70</td>
</tr>
</tbody>
</table>

Pakistan’s Fauji Kabir Wala, Jamshoro, and Habibullah plants fit into this category. Currently, Habibullah has provided RAM KPI data for AF. Comparison to the AF distribution for peers shows that it’s AF of 84.43% over the last 6 ½ years puts its AF performance at the 26th percentile, suggesting that there may be substantial opportunity for improvement. Fauji Kabirwala’s AF of 83.58% for 2005 puts it at the 27th percentile. However, it was noted that the vast majority of its unavailability was from a major overhaul done after 6 years of operation, so that a more detailed trend of its data would be necessary to gauge its potential for improvement.

GROUP 4 – Larger Combined Cycle Units

Select Criteria: 200MW – 600MW. There were 55 units in this peer group.

Table 4

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>74.49</td>
<td>81.79</td>
<td>86.32</td>
<td>84.19</td>
<td>93.02</td>
<td>96.76</td>
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<tr>
<td>ELR</td>
<td>2.58</td>
<td>4.16</td>
<td>7.87</td>
<td>10.37</td>
<td>23.20</td>
<td>32.07</td>
</tr>
<tr>
<td>POF</td>
<td>0.0</td>
<td>1.73</td>
<td>3.64</td>
<td>5.53</td>
<td>7.90</td>
<td>11.33</td>
</tr>
</tbody>
</table>

Pakistan’s Liberty, Guddu, Kapco and Rousch plants are included in this peer group. Rousch’s AF of 89.93% puts it at the 35th percentile of its peers indicating an opportunity for improvement. Its POF of 2.73% puts it at the 35th percentile of its peers for planned outages (low percentiles
for POF are good), indicating a minimal likelihood for cost-effective improvement in this area. Its Forced Outage Rate (FOR) (similar to ELR except that the effect of unplanned deratings are not included) of 7.8% puts it at the 80th percentile of its peers, indicating a strong possibility for improvement. Guddu’s AF in 2005 was 90.47%, putting it at the 40th percentile and indicating an opportunity for some improvement.

**GROUP 5 – Hydroelectric Units**

**Select Criteria:** 150MW – 350MW. There were 45 units in this peer group.

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>76.81</td>
<td>84.42</td>
<td>91.06</td>
<td>88.90</td>
<td>93.74</td>
<td>95.04</td>
</tr>
<tr>
<td>ELR</td>
<td>0.68</td>
<td>0.94</td>
<td>1.79</td>
<td>2.63</td>
<td>2.82</td>
<td>8.45</td>
</tr>
<tr>
<td>POF</td>
<td>3.31</td>
<td>4.52</td>
<td>7.41</td>
<td>8.72</td>
<td>11.30</td>
<td>16.92</td>
</tr>
</tbody>
</table>

Pakistan’s Tarbella and Ghazi Barotha plants fall into this category. Ghazi Barotha data shows that its five units averaged an EAF of 91.48% in 2005 putting it at the 56th percentile (slightly better than average).

**GROUP 6 – Diesel Units**

Almost all of the diesel units in the NERC-GADS database have very low load factors and very small sizes. Therefore, it would not be appropriate to use NERC-GADS data to set standards for Pakistan’s diesel units, especially for ELR and POF. However for comparisons sake, the EAF for the 111 diesel units in the NERC-GADS database are shown below.

<table>
<thead>
<tr>
<th>Percentile</th>
<th>10th</th>
<th>25th</th>
<th>50th</th>
<th>mean</th>
<th>75th</th>
<th>90th</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPI</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAF</td>
<td>86.28</td>
<td>92.43</td>
<td>96.31</td>
<td>92.41</td>
<td>99.32</td>
<td>99.80</td>
</tr>
</tbody>
</table>

Kohinoor reported a 93.13% AF in 2005. Since the available data is not directly applicable, an estimation of its potential for improvement is not practical.
Appendix-5

Performance Data for World Energy Council Database

Key Performance Indicators (KPI)

- Energy Availability Factor (EAF) = (AH-EUDH-EPDH)/PH.
- Unit Capability Factor (UCF) = EAF without OMC
- Unit Loss Capability Factor = 1-UCF
- Energy Loss Rate (ELR) =
  \[
  \frac{(UOH \text{ without OMC} + EUDH \text{ without OMC})}{(SH + UOH \text{ without OMC})}
  \]
- Equivalent Unplanned Outage Factor (EUOF) =
  \[
  \frac{(UOH \text{ without OMC} + EUDH \text{ without OMC})}{PH}
  \]
- Equivalent Planned Outage Factor (EPOF) =
  \[
  \frac{(POH \text{ without OMC} + EPDH \text{ without OMC})}{PH}
  \]
- Net Capacity Factor (NCF) = (NAG)/(RC*PH)
- Net Output Factor (NOF) = (NAG)/(RC*SH)

(* “OMC” is “outside management control” outages or de-rates. These are events as a result of nature such as ice storms, lightning, tornados and other severe weather that result in unit outages or transmission downtime where the unit cannot transmit power).

Required Elements for KPI Calculations (this data should be input for each month for each unit)

Reference Capacity (RC) in MW
 RC is the unit’s maximum dependable generating capacity less any station service or auxiliary power (in MW). RC is determined when there are no short term equipment problems causing a temporary derating of the unit and all major equipment is operating at full load under designed temperatures and pressures.

Net Actual Generation (NAG) in MW-HR
 NAG is the unit’s Gross Actual Generation less any generation utilized for that unit’s station service or auxiliary loads. If NAG is negative during the month being reported, enter a minus sign in the column immediately before the reported value.

Attempted Unit Starts
 Enter the number of attempts made to start the unit during the month to either generate, pump or synchronous condense where the unit goes from a stopped position to generate, pump or synchronous condensing mode. Repeated initiations of the starting sequence without accomplishing corrective repairs are counted as a single attempt.

If startup attempts are abandoned and the unit is shut down for repairs and then started at a future time, report two startup attempts.
Actual Unit Starts
Enter the number of times the unit actually starts during the month to generate, pump or condense where the unit goes from a stopped position to generate, pump or synchronous condensing mode.

The number of actual unit starts must be less than or equal to the number of attempted unit starts.

Unit Service Hours (or Unit Operating Hours) (SH)
Enter the number of hours the unit was synchronized to the system. For units equipped with multiple generators, count only those hours when at least one of the generators was synchronized, whether or not one or more generators were actually in service.

Reserve Shutdown Hours (or Economic Hours) (RSH)
Enter the sum of all hours the unit was available to the system but not synchronized for economy reasons. During the RSH time, the unit is capable of generating but is not because it is not needed for load or management decides not to operate it.

Pumping Hours
Enter the number of hours the hydro turbine/generator operated as a pump/motor.

Synchronous Condensing Hours
Enter the number of hours the unit operated in the synchronous condensing mode (applies primarily to hydro/pumped storage and some combustion turbine units). Do not report these hours as Unit Service Hours.

Available Hours (AH)
Enter the sum of the Unit Service Hours, Reserve Shutdown Hours, Pumping Hours (if applicable), and Synchronous Condensing Hours (if applicable).

Planned Outage Hours (POH) excluding OMC outages
Enter the sum of all hours the unit was off-line due to Planned Outages (outages planned well in advance such as annual overhauls).

Unplanned Outage Hours (UOH) excluding OMC outages
Enter the sum of all hours the unit was off-line due to unplanned outages and startup failure outages.

Period Hours (PH)
Enter the number of hours in the month being reported that the unit was in the active state. The sum of Available Hours and Unavailable Hours (total of POH + UOH) must equal Period Hours.

Equivalent Planned Derated Hours (EPDH) excluding OMC derates
Enter the sum of all equivalent hours the unit was temporarily reduced (restricted, derated) from its Reference Capacity due to Planned Deratings. These hours are computed from deratings (restrictions) only and do not include full, complete outage hours.
To compute equivalent hours:
Each individual Planned Derating is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Reference Capacity (RC). These equivalent hour(s) are then summed.

\[
\text{Derating Hours} \times \frac{\text{Size of Reduction}}{\text{RC}}
\]

The “size of reduction” is reference capacity minus temporary capacity as a result of the derating or restriction.

**Equivalent Unplanned Derated Hours and Startup Failure Hours (EUDH) excluding OMC derates**

Enter the sum of all equivalent hours the unit was temporarily reduced (restricted, derated) due to Unplanned Deratings. These hours are computed from deratings (restrictions) only and do not include full, complete outage hours.

To compute equivalent hours:
Each individual Unplanned Derating is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Reference Capacity (RC). These equivalent hour(s) are then summed.

\[
\text{De-rating Hours} \times \frac{\text{Size of Reduction}}{\text{RC}}
\]

The “size of reduction” is reference capacity minus temporary capacity as a result of the derating or restriction.
Appendix-6

Design Data for World Energy Council Database

GAS TURBINES & JET ENGINES
A gas turbine is an internal combustion rotary engine. The engine burns a lean mixture of fuel with compressed air. The hot pressurized gases expand through a series of rotating turbine wheel and blade assemblies resulting in shaft power output, propulsive thrust, or a combination of the two. When one or more gas turbines/jet engines are connected to a heat recovery steam generator and a steam turbine/generator the total capacity is considered a single Combined Cycle (CC) unit and should be reported as such. If the CC steam turbine/generator was added after the simple-cycle gas turbines had been reporting, stop reporting the gas turbine data, redefine the total capacity as parts of a Combined Cycle unit (see design data input requirements for Combined Cycle units) and begin reporting the performance data as a single combined cycle unit.

- **Country code** (assigned by WEC offices) – This code identifies the country sending data to the WEC.

- **Company code** (assigned by WEC data reporter) – This code identifies the reporting company providing WEC with data. It is recommended the code be for the reporting utility within the country.

- **Generating unit code** (assigned by WEC data reporter) – This code identifies the specific unit in the reporting company. This helps give the generating unit a unique number.

- **Year and month the unit was first commercially operated**
  Criteria: a) The date the unit was first declared available for dispatch at some level of its capability, OR

  b) The date the unit first operated at 50% of its generator nameplate megawatt capability (product of the mega-volt-amperes (MVA) and the rated power factor as stamped on the generator nameplate(s)).

- **Engine type** - (Gas turbine single shaft; Gas turbine split shaft; Jet engine (aero derivative); Other, describe: ________________________)

- Enter the number from the list below that best describes the mode of operation for the unit as it was originally designed:
  Loading Characteristic: ____________________
  1 - Base load with minor load following
  2 - Periodic start-up, load follow daily, reduced load nightly
  3 - Weekly start-up, load follow daily, reduced load nightly
  4 - Daily start-up, load following daily, off-line nightly
- Start-up chiefly to meet daily peaks
- Seasonal operation only
- Other, describe ________________________________

- **Type of fuel** that the generating unit was designed to burn

- **MW nameplate rating**
  Nameplate is the design capacity stamped on the gas turbines/jet engines or published on the guarantee flow diagram. In cases where the gas turbine’s nameplate rating cannot be determined, approximate the rating by multiplying the MVA (megavolt amperes) by the rated power factor found on the nameplate affixed to each unit’s generator (or nameplates in the case of cross compound units).

**COMBINED CYCLE BLOCKS**
A Combined Cycle (CC) block is a process for generating energy (either electricity or steam) constituted by the marriage of a Brayton Cycle (expand hot gas to turn a gas turbine) with a Rankin Cycle (use heat to boil water to make steam to turn a steam turbine). The Combined Cycle block employs an electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas turbines/jet engines, one or more steam turbines, and balance of plant equipment supporting the production of electricity. In the combined cycle block the exiting heat is routed to a conventional boiler or to a heat recovery steam generator (HRSG) for use by a steam turbine in the production of electricity or steam energy. When a steam turbine/generator is added to one or more existing gas turbines/jet engines that have been reporting as simple cycle units, stop reporting the data as simple cycle units, redefine the total capacity as parts of a Combined Cycle unit and begin reporting the performance data as a single Combined Cycle unit.

- **Country code** (assigned by WEC offices) – This codes identifies the country sending data to the WEC.

- **Company code** (assigned by WEC data reporter) – This code identifies the reporting company providing WEC with data. It is recommended the code be for the reporting utility within the country.

- **Generating unit code** (assigned by WEC data reporter) – This code identifies the specific unit in the reporting company. This helps give the generating unit a unique number.

- **Year and month the unit was first commercially operated**
  Criteria:  
  a) The date the unit was first declared available for dispatch at some level of its capability, or

  b) The date the unit first operated at 50% of its generator nameplate megawatt capability (product of the mega-volt-amperes (MVA) and the rated power factor as stamped on the generator nameplate(s)).
• **Block Loading Characteristics at Time of Design**
  Enter the number from the list below that best describes the mode of operation for the block as it was originally designed:
  1 - Base load with minor load following
  2 - Periodic start-up, load follow daily, reduced load nightly
  3 - Weekly start-up, load follow daily, reduced load nightly
  4 - Daily start-up, load follow daily, off-line nightly
  5 - Start-up chiefly to meet daily peaks
  7 - Seasonal operation only
  9 - Other, describe

• **Total Nameplate Rating of all units in the block (in MW)**
  Enter the TOTAL capability (sum of all gas turbines/jet engines and steam turbines) MW nameplate or published MW rating of the block. In cases where the turbine’s nameplate rating cannot be determined, approximate the rating by multiplying the MVA (megavolt amperes) by the rated power factor found on the nameplate affixed to each unit’s generator (or nameplates in the case of cross compound units).

• **Does the block have co-generation** (steam for other than electric generation) capabilities (yes/no)? ____

• **What is the number of gas turbines/jet engines per Heat Recovery Steam Generator (HRSG)?** Identify the number of gas turbines/jet engines feeding exhaust gases into a single HRSG.

• **What is the number of gas turbines/jet engines and Heat Recovery Steam Generator (HRSG) Trains?** Identify the number of sets of gas turbines/jet engines and HRSG trains supplying steam to the steam turbine.

• **Total number of gas turbines/jet engines in block.** Identify the number of GT/Jets used for generating power.

• **Total number of Heat Recovery Steam Generator (HRSG) in block.** Identify the number of HRSG supplying steam to the steam turbine.

• **Total number of Steam Turbines in block.** Identify the number of steam turbines receiving steam for generating power.

• **Type of fuel** that the gas turbine/jet units were designed to burn.

**FOSSIL STEAM UNITS**
Fossil-steam units are those units with a single steam generator connected to a single or cross compound turbine-generator drive train. Steam is created in a single boiler and then transferred through piping to a single steam turbine. The steam turbine is connected to the generator for producing electric power.
- **Country code** (assigned by WEC offices) – This code identifies the country sending data to the WEC.

- **Company code** (assigned by WEC data reporter) – This code identifies the reporting company providing WEC with data. It is recommended the code be for the reporting utility within the country.

- **Generating unit code** (assigned by WEC data reporter) – This code identifies the specific unit in the reporting company. This helps give the generating unit a unique number.

- **Year and month the unit was first commercially operated**
  Criteria: a) The date the unit was first declared available for dispatch at some level of its capability, OR
  b) The date the unit first operated at 50% of its generator nameplate megawatt capability (product of the megavolt amperes (MVA) and the rated power factor as stamped on the generator nameplate(s)).

**Unit Loading Characteristics at Time of Design**
Enter the number from the list below that best describes the mode of operation for the unit as it was originally designed:

1 - Base load with minor load following
2 - Periodic start-up, load follow daily, reduced load nightly
3 - Weekly start-up, load follow daily, reduced load nightly
4 - Daily start-up, load follow daily, off-line nightly
5 - Start-up chiefly to meet daily peaks
7 - Seasonal operation only
9 - Other, describe ___________________________________________________________________________

- **Boiler - Fuel Firing System**
Enter the type of fuel firing system the unit was designed for:
  A - *Front OR Back* - wall mounted burners on either the front OR the back of the furnace.
  B - *Opposed* - wall mounted burners on BOTH the front and back of the furnace.
  C - *Vertical* - burners are mounted on the ceiling of the furnace.
  D - *Tangential* - firing from the corners of the furnace with burners capable of directing the fireball up or down.
  E - *Cyclone* - horizontal (burner) cylinders connected to furnace walls wherein fuel and air are combusted in a controlled environment. Combustion gases exit through re-entrant throat into furnace, and slag drains to slag tanks. Cyclone burners may be installed in either single walls or opposed walls.
  F - *Concentric* - staged combustion system, designed primarily for NO₂ control, in which the walls are blanketed with air.
G - *Circulating fluidized bed* - upward flow of air holds the fuel and sorbent particles (e.g., limestone) in suspension in the combustion zone. Partially burned fuel passes into a collector and is routed back into the combustion zone.

H - *Bubbling fluidized bed* - similar to circulating fluidized bed except the partially burned fuel is not re-circulated.

I - *Stoker* - overfeed method combined with suspension firing.

J - Other, describe: ________________________________

- **Boiler - Type of Circulation**
  Enter the type of circulation the boiler was originally designed for:
  1 - *Natural (thermal)* - water flows through furnace wall tubes unaided by circulating pumps. Primarily used with sub-critical units.
  2 - *Controlled (forced or pump assisted thermal)* - water flows through furnace wall tubes aided by boiler recirculation pumps located in the down-comers or lower headers of the boiler. Used on some sub-critical units.
  3 - *Once through* - no recirculation of water through the furnace wall tubes and no steam drum. Used on supercritical and some sub-critical units.

- **Boiler - Type of Furnace Bottom**
  Enter the type of furnace bottom the boiler was originally designed for:
  1 - *Dry bottom* - no slag tanks at furnace throat area (throat area is clear). Bottom ash drops through throat to bottom ash water hoppers. Design used when ash melting temperature is greater than temperature on furnace wall, allowing for relatively dry furnace wall conditions.
  2 - *Wet Bottom* - slag tanks installed at furnace throat to contain and remove molten ash from the furnace.

- **Type of fuel** that the generating unit was designed to burn

- **Boiler - Balanced Draft or Pressurized Draft**
  Enter the type of draft the boiler was designed for:
  1 - *Balanced draft* - equipped with both induced draft and forced draft fans. The furnace operates at positive pressure at air entry and negative pressure at flue gas exit.
  2 - *Pressurized draft* - equipped with forced draft fans only. The furnace and draft system operate at positive pressure.

  IF the unit was designed as a pressurized draft unit and converted to a balanced draft design, enter the date the conversion was completed: ____________________.

- **Boiler - Mechanical Fly Ash Precipitator System**
  Fly ash contained in the furnace exit flue gases can be removed by various types of mechanical precipitators including cyclone collectors, and wet or venturi scrubbers. Enter the following information on the mechanical precipitator equipment:
Enter the location of the mechanical precipitator with respect to the air heaters:
1 - Before air heaters
2 - After air heaters
3 - Both - precipitators installed both before and after the air heaters.
9 - Other, describe: ______________________________

**Boiler - Electrostatic Precipitator**

Fly ash contained in the furnace exit flue gases can be removed by using an electrostatic precipitator. Enter the following information on the electrostatic precipitator:

Enter the location of the electrostatic precipitator with respect to the air heaters:
1 - Before air heaters
2 - After air heaters
3 - Both - Flue gas is extracted both before and after the air heaters.
9 - Other, describe: ______________________________

- **Flue Gas Desulfurization Data**
  Enter the year the FGD system was initially operated: __________________

Was the FGD system a part of the original design of the unit? A “no” answer means the FGD system was a retrofit after the unit entered service. (yes or no)

**FGD Cycle Type**
1 - *Single loop* - single recirculation loop for controlling the reagent.
2 - *Dual loop* - two separate and distinct recirculation loops for controlling the reagent (same reagent used in both loops).
3 - *Dual alkali* - two separate and distinct reagents controlled through the use of separate recirculation loops operated in series.
9 - *Other*

- **MW nameplate rating.**
  Nameplate is the design capacity stamped on the gas turbines/jet engines or published on the guarantee flow diagram. In cases where the gas turbine’s nameplate rating cannot be determined, approximate the rating by multiplying the MVA (megavolt-amperes) by the rated power factor found on the nameplate affixed to each unit’s generator (or nameplates in the case of cross compound units).

- **Steam Turbine - Type of Steam Turbine**
  Identify the steam turbine’s casing or shaft arrangement.
1 - *Single casing* - single (simple) turbine having one pressure casing (cylinder).
2 - *Tandem compound* - two or more casings coupled together in line.
3 - *Cross compound* - two cross-connected single casing or tandem compound turbine sets where the shafts are not in line.
4 - **Triple compound** - three cross-connected single casing or tandem compound turbine sets.

9 - **Other, describe**: __________________________________________

**Steam Turbine - Steam Conditions**

Enter the following information on the Main, First Reheat, and Second Reheat Steam design conditions:

<table>
<thead>
<tr>
<th></th>
<th>Temperature (°F)</th>
<th>Pressure (psig)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main steam</td>
<td></td>
<td></td>
</tr>
<tr>
<td>First reheat</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Second reheat</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Or

<table>
<thead>
<tr>
<th></th>
<th>Temperature (°C)</th>
<th>Pressure (kPA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main steam</td>
<td></td>
<td></td>
</tr>
<tr>
<td>First reheat</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Second reheat</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Auxiliary Systems - Main Condenser**

Enter the following information for the main condenser and its auxiliaries:

Enter the type of cooling water used in the condenser:

1 - *Fresh* - salinity values less than 0.50 parts per thousand.
2 - *Brackish* - salinity value ranging from approximately 0.50 to 17 parts per thousand.
3 - *Salt* - salinity values greater than 17 parts per thousand.
9 - **Other, describe**: ____________________

Enter the origin of the circulating water used in the condenser:

1 - River
2 - Lake
3 - Ocean or Bay
4 - Cooling Tower
9 - **Other, describe**: ____________________

**NOX Reduction Systems**

These systems include Selective Non-catalytic Reduction, Selective Catalytic Reduction, Catalytic Air Heaters, and Staged NOX Reduction, which is a combination of the three methods. Excluded from this category are Low NOX burners, combustion modifications, and flue gas recirculation.

Please complete the following information for the NOX Reduction Systems installed on your unit.

- Selective Non-Catalytic Reduction System (SNCR) (yes or no)
- Selective Catalytic Reduction System (SCR) (yes or no)
DIESEL UNITS (INTERNAL COMBUSTION ENGINES)

Diesel units are internal combustion units. The fuel enters cylinders inside the engine block and when fired, results in shaft movement. The shaft movement rotates the generator and produces power.

- **Country code** (assigned by WEC offices) – This code identifies the country sending data to the WEC.

- **Company code** (assigned by WEC data reporter) – This code identifies the reporting company providing WEC with data. It is recommended the code be for the reporting utility within the country.

- **Generating unit code** (assigned by WEC data reporter) – This code identifies the specific unit in the reporting company. This helps give the generating unit a unique number.

- **Year and month the unit was first commercially operated**
  Criteria: a) The date the unit was first declared available for dispatch at some level of its capability, OR
  b) The date the unit first operated at 50% of its generator nameplate megawatt capability (product of the mega-volt-amperes (MVA) and the rated power factor as stamped on the generator nameplate(s)).

- **Unit Loading Characteristics at Time of Design**
  Enter the number from the list below that best describes the mode of operation for the unit as it was originally designed:
  1 - Base load with minor load following
  2 - Periodic start-up, load follow daily, reduced load nightly
  3 - Weekly start-up, load follow daily, reduced load nightly
  4 - Daily start-up, load follow daily, off-line nightly
  5 - Start-up chiefly to meet daily peaks
  7 - Seasonal operation only
  9 - Other, describe

- **Type of fuel** that the generating unit was designed to burn

- **Cycle, type** - (1) 2-stroke; (2) 4-stroke; (9) Other, describe: ___________

- **MW nameplate rating.**
  Nameplate is the design capacity stamped on the gas turbines/jet engines or published on the guarantee flow diagram. In cases where the gas turbine’s nameplate rating cannot be determined, approximate the rating by multiplying the MVA (megavolt-amperes) by the rated power factor found on the nameplate affixed to each unit’s generator (or nameplates in the case of cross compound units).
HYDRO AND PUMPED STORAGE UNITS
Hydro and pumped storage units are generating units using water as its fuel. Hydro units can use river water, water from over the spillways of dams or other water sources. Pumped storage units can be used as both a generator and a motor. As a generator, it provides electric power; as a motor it pumps water back into the reservoir to be used at a later date for generating power.

- **Country code** (assigned by WEC offices) – This code identifies the country sending data to the WEC.

- **Company code** (assigned by WEC data reporter) – This code identifies the reporting company providing WEC with data. It is recommended the code be for the reporting utility within the country.

- **Generating unit code** (assigned by WEC data reporter) – This code identifies the specific unit in the reporting company. This helps give the generating unit a unique number.

- **Year and month the unit was first commercially operated**
  Criteria: a) The date the unit was first declared available for dispatch at some level of its capability, or
  b) The date the unit first operated at 50% of its generator nameplate megawatt capability (product of the mega-volt-amperes (MVA) and the rated power factor as stamped on the generator nameplate(s)).

- **Unit Loading Characteristics at Time of Design**
Enter the number from the list below that best describes the mode of operation for the unit as it was originally designed:
1 - Base load with minor load following
2 - Periodic start-up, load follow daily, reduced load nightly
3 - Weekly start-up, load follow daily, reduced load nightly
4 - Daily start-up, load follow daily, off-line nightly
5 - Start-up chiefly to meet daily peaks
7 - Seasonal operation only
9 - Other, describe

- **MW nameplate rating**
Nameplate is the design capacity stamped on the gas turbines/jet engines or published on the guarantee flow diagram. In cases where the gas turbine’s nameplate rating cannot be determined, approximate the rating by multiplying the MVA (mega-volt-amperes) by the rated power factor found on the nameplate affixed to each unit’s generator (or nameplates in the case of cross compound units).

- **Type of unit**: (1) Hydro; (2) Pump/turbine; (3) Pump
- **Turbine/Pump reaction type** - (1) Francis; (2) Kaplan – adjustable blade propeller; (3) Fix blade propeller; (4) Pump/turbine; (9) Other, describe: _____________
- **Turbine rated head to nearest foot**: ________________
Appendix-7

ELECTRICITY GENERATION PERFORMANCE STANDARDS
BRIEF/MINUTES ON PPIAF STUDIES

Mr. Robert R. Richwine Jr was engaged by NEPRA and the World Bank to develop Generation Performance Standards through Public-Private Infrastructure Advisory Facility (PPIAF) support. Mr. Richwine started his assignment in April, 2006 and visited Pakistan for a week during last half of April. Later on Mr. Richwine submitted an Inception Report about the Study, requesting information for existing and historical statistics. The data requirements were sent to all stakeholders by NEPRA and the data so gathered was provided to Mr. Richwine for his report.

2. During the last week of June, 2006 Mr. Richwine submitted a Draft Final Report which was circulated to all the stakeholders and to the Authority Members for their views and comments. The report identifies the following areas for which standards would be relevant for power generation facilities:-

i) Power Quality (voltage, reactive power, frequency)
ii) Environmental (NEQS)
iii) Safety (being followed individually)
iv) Reliability, Availability, Maintainability (RAM) Consisting of:
   - Energy Loss Rate (ELR)
   - Energy Availability Factor (EAF)
   - Planned Outage Factor (POF)
v) Efficiency
vi) Costs

The report provides discussion and Mr. Richwine's recommendations on the implementation of these.

3. Mr. Richwine also visited Pakistan during the second week of July, 2006 and NEPRA, World Bank Team along with Mr. Richwine met with relevant officers of the Ministries, WAPDA and KESC. Meetings were also held with Adviser to the Prime Minister on Energy.
Chairman WAPDA, and CEO KESC. One full day workshop on the concepts at Lahore and two training workshops at Lahore and Karachi were also conducted. Mr. Richwine also gave detailed presentation to the Authority on 10th July 2006. At the conclusion of his visit, Mr. Richwine held a meeting with Member (Standards) on 14th July, 2006.

4. The following observations were made in the Report, in meetings with the stakeholders and specifically during meetings with the Authority and Member (Standards).

4.1) It was observed that Power Quality Standards which consist of Voltage Stability, Turbine Operation and Reactive Capacity are covered in Grid Code therefore, Generation Performance Standards may include these only as indicators while no obligation would be placed on the generators.

4.2) With reference to the environmental standards it was observed that NEPRA conform to the environmental standards formed by EPA Pakistan and the NEQS.

4.3) He pointed out that the safety standards also relate to internal working of the generators and as such NEPRA may not be able to prescribe these.

4.4) With reference to efficiency standards, Mr. Richwine noted that plant heat rates depend on a large number of factors including site conditions, investments in the equipment, plant operations etc. He stated that it is obvious that the heat rate values will deteriorate with time from that of the designed heat rates. He proposed that the theoretically achievable heat rate should be determined on regular basis and a margin of two to four percent from those could be allowed in actual operation. He further observed that heat rates can not be prescribed by NEPRA and at best NEPRA can initiate heat rate testing program which will be used by the generators to work out their theoretical heat rates.
4.5) About cost standards he recommended that NEPRA needs to initiate data collection efforts with respect to costs from international sources also so that reasonably acceptable databank is developed.

4.6) With respect to the RAM standards which relate to the availability of the power plants he recommended that NEPRA should immediately initiate collection of data, according to internationally acceptable definitions to be included in the Final Report. These definitions relate to Energy Loss Rate (ELR), Energy Availability Factor (EAF) and Planned Outage Factor (POF). Initially monthly data may be collected which may be expanded to include historical data. Based on this data NEPRA may set benchmarks for the generators to improve their availability.

4.7) It was stressed by the World Bank that the generators should not see these standards as additional imposition by NEPRA.

5. Mr. Richwine recommended to the Authority that in order to guide the generation sector the following steps are needed.

5.1) For the benchmarking exercise NEPRA may either use North American Electric Reliability Council (NERC) databank or World Energy Council (WEC) databank. NERC has offered to provide copies of Software at half the price (US$2000). NEPRA is strongly recommended to purchase this software.

5.2) Since the generation performance standards would include directions for the generators to provide data with respect to different standards as noted above including Safety, RAM, Efficiency and Costs, it is recommended that a core group be established within the Standards Division who will be responsible for all matters related to the data collection, compilation, analysis and providing feedback to the stakeholders.
5.3) For the cost collection NEPRA is required to become a member of international group which deals with the collection of cost over the world.

5.4) NEPRA is encouraged to become member of the power generation performance group and a NEPRA professional may be nominated to coordinate with the power generation performance group under the World Energy Council (WEC).

6. The Authority agreed with the recommendation of the consultant and directed Director (S&P) to initiate necessary steps as the final report is submitted by the end of July 2006.
Appendix 8 – Using Past Performance Data to Improve Future Performance

Case Study of the Month - January 2003

Performance Data to Performance Improvement:
Answering the $80 Billion per Year Question - STEP ONE

Prepared by Robert Richwine
Power Plant Reliability Management Consultant
Chairman, Working Group on Workshops and Communications
Performance of Generating Plant Committee
World Energy Council

US$80 Billion per year PLUS 1 Billion Tonnes of CO2 reduction!!!

This is the potential positive economic and environmental impact that the World Energy Council estimates would result from closing the gap between the average performance currently being achieved by the worldwide fleet of generating plants and the level of performance that "the best class" plants are achieving. It has also been proven that the greatest performance gains for the least cost are obtained through better management of the generating plants (see our May 2002 Case Study "Design or Management - Which Influences your Plant's Reliability Most?"). This month's case study will begin a four part series that will demonstrate how top performing generating companies collect, share and analyze performance data and have achieved improved the performance of their plants as a result.

During many of the workshops conducted by the World Energy Council's (WEC) Performance of Generating Plant (PGP) Committee, we have been presented with the results of numerous successful Performance Improvement Programs implemented by companies from many regions throughout the world. While each program has been unique it its details, we have observed that most have a few key steps in common. Also, and what is pertinent to these monthly Case Studies, these common steps all emphasize how performance data contributes to improved generating plant performance.

This month's Case Study will describe in general the four steps common to successful Performance Improvement Programs: 1) Awareness, 2) Identification, 3) Evaluation, and 4) Implementation. In addition it will examine in detail how performance data are used in Step 1, Awareness. The following three monthly case studies will examine data usage in Steps 2, 3 and 4.

COMMON STEPS IN SUCCESSFUL PERFORMANCE IMPROVEMENT PROGRAMS

Step 1) Awareness

The first step in successful Performance Improvement Programs is to make company executives, managers, and generation staff aware of the potential for improvement that exists at each of the company's plants and the importance of achieving that potential. Later in this case study two of
the most important of the many possible actions that can be taken to enhance the awareness of
that potential will be described in more detail:

1. Benchmarking of current plant performance
2. Economic Value of Improved Performance

Step 2) Identification

The ability to identify a wide range of "best practice" options aimed at performance
improvement is an increasingly important requirement in managing power plants in today's cost-
conscious business environment. In the past it was perhaps adequate to simply identify the "best"
technical option, obtain financing for that option and then implement that option at the lowest
possible cost. However, in today's increasingly market-based business environment, an entire
range of viable options must be identified, so that the most cost-effective option can be
determined. The effective use of every available channel to identify those viable options, from
original equipment manufactures to consultants recommendations, to local plant staff insights
perhaps the most valuable of all) is necessary to be able to determine the best use of the
company's available (but limited) resources. Next month's case study will describe in more detail
some of these "identification" techniques being used by "best in class" companies.

Step 3) Evaluation

After all viable options have been identified (Step 2), their cost and technical impacts on plant
performance must be estimated and combined with the worth of unit improvement (Step 1) so
that each option can be economically evaluated. All financially justifiable projects can then be
prioritized across unit, plant and company levels to ensure that the most cost-effective options
are chosen. Decision support tools that can automate this activity are also needed to expedite this
process and provide the necessary documentation quickly and cost-effectively. A future month's
case study will describe this process in more depth.

Step 4) Implementation

After reviewing the output of the Evaluation process (Step 3) the most cost effective set of
options must be chosen for funding. Final decisions must also include each candidate project's
intangible aspects as well as its economic aspects. Intangibles historically have included factors
such as employee moral, corporate image, safety, customer satisfaction and environmental
impact (although environmental impact is increasingly able to be quantified in monetary terms so
that projects with high positive environmental impact will have higher benefit to cost ratios and
are more likely to be chosen for implementation). Financing for those projects that are finally
chosen must be arranged and the projects designed and installed. Performance goals for the
plants where the projects are installed must be set giving proper consideration to the expected
performance improvement stated in the prioritization analysis. Finally, the actual results
achieved after the project has been installed should be calculated and compared to the expected
impact. This should be done so those successful projects can be repeated at other plants and
unsuccessful projects rejected or modified to increase their chances of success elsewhere. This
post installation comparison of expected verses actual results will then be fed back into the
Awareness and identification steps and thereby closes the loop on the process of continuing improvement.

**AWARENESS**

The first step in successful Performance Improvement Programs is to create Awareness in the company's generation executives and staff of the opportunity for improvement in their plant's technical performance and the economic and environmental benefits resulting from that improvement. Accurate and consistent data plays a vital role in creating that awareness. Although data is used in numerous ways in the Awareness step, this discussion will focus on two of the most important: 1) Benchmarking of current plant performance and 2) Economic Value of Improved Performance.

**Benchmarking**

Previous case studies (April 2002, August 2002) have described examples of benchmarking and how benchmarking has helped generating companies:

1. Set realistic, achievable goals - In setting performance goals it is important to have an aggressive goal that causes the plant management to strive to improve, yet one that is possible to achieve. It is also important that this goal-setting process be objective and easy for everyone to understand so that the results are accepted as reasonable plant expectations. Comparing the plant's historical performance to the performance of its peers (see our case study from August 2002 for discussion of proper peer selection process) will help in selecting these goals.

2. Identify opportunities for improvement - By analyzing plant system and component data from similar (peer) plants, we can find areas within the plant that we should focus on that have the most potential for cost-effective improvement projects. This will be further discussed in next month's case study when we focus on Step 2) Identification.

3. Give advance warning of potential problems - Analyzing data from other similar (peer) plants can also alert us to problems that they have faced that we may encounter in the future. Our Case Study of February, 2002, describes one way in which a progressive generating company used peer data to proactively develop cost-effective actions in order to prevent, detect or minimize the consequences of High Impact-Low Probability (HILP) events.

4. Trade knowledge and experiences with peers - By identifying other plants with similar designs and modes of operation to our plants, we can begin to directly communicate with them in order to share our experiences and knowledge. Adapting their successful programs to our unique situation will give us a path to "get down the learning curve" much quicker. (see our case study for November 2002 for an application of learning curve theory).

5. Determine appropriate incentives - Often, plant management is given financial or other types of incentives based on their plant's performance. Benchmarking can help to quantify the appropriate incentives to offer.

6. Quantify and manage performance risks - As we more into a more competitive business environment, it will be necessary to identify, quantify and manage risks, instead of
simply avoiding risks. The insight and data coming from benchmarking will be invaluable in attaining the necessary proficiency in risk management (this is a very complex area that merits a case study of its own which we will be publishing later in the year).

**Economic Value of Improved Performance**

One of the most important activities in any awareness campaign is to estimate the short and long term value the company receives from the improvement in each aspect of a unit's performance; i.e. availability, reliability (forced outage rate), efficiency (heat rate), auxiliary equipment power requirements, capacity, etc. In addition, as market-based emissions trading processes evolve, it will become possible to forecast the financial impact to a unit's bottom-line profitability due to its environmental performance. Understanding the value to the company has proven highly motivating to the generation staff in developing better day-to-day decisions process. This worth data will also be used during Step 3) Evaluation, when we will seek to justify and prioritize the many improvement projects competing for the plant's limited resources.

Value of improved performance of the company's generating plants is derived from one or more of the following areas:

1. **Reduced fuel costs** - Improving the efficiency of an individual plant means the plant uses less fuel, resulting in an obvious savings. Also, improved reliability of a more efficient plant will allow that plant to replace the generation that would otherwise have to be generated from a less efficient plant. Therefore, the total fuel cost for the company would be less. In addition the emissions in both of the above cases would be less in order to meet the same customer demand for electricity.

2. **Deferred new plant construction costs** - Increasing the reliability of the company's plants has the effect of delaying new capacity construction required to meet increasing demand since the current fleet is able to generate more electricity. At one company whose installed capacity was in excess of 30,000 MW, a one percentage point increase in reliability allowed the deferral of over 300 MW of new capacity for a documented savings of over $100,000,000 dollars.

3. **Reduced reserve margin criteria** - When the reliability of a company's generating plant fleet is low, the expansion planning organization often must increase the reserve margin in order to compensate in order to provide a reasonable level of customer service reliability. At one company whose Equivalent Availability was only 50%, the planning reserve margin was **100%**! After implementing an aggressive Availability Improvement Program, they were able to raise their Availability to over 80% and were able to reduce their reserve margin to approximately 25%. Another large company raised their Availability from 68% to 92+% and was able to lower their reserve margin from 40+% to 13%. These savings are carried forward indefinitely into the future if the company is able to sustain the higher levels of generating plant reliability.

4. **Higher customer service reliability** - In many countries around the world, low levels of customer service reliability translate directly into low economic growth. Giving current and potential future customers the confidence that the electricity supply is reliable will help to ensure long term economic prosperity for the company and the country. While
this area is much more difficult to quantify than the first three (above), it can be higher than the other three combined where customers are experiencing a high incident of electricity service interruptions.

While the forecasts of the economic value of improved performance are not easy to make, it is important to make the estimates and then publicize the results throughout the company. At one company where a formal Availability Improvement was successfully implemented, one plant staff executive commented "The Availability Improvement Program gave an insight into the value of availability, changing the plant staff's perception of generation and demonstrated the value of a reliable operating plant ".

CONCLUSIONS

Several important conclusions can be reached based on the experience of generating companies worldwide that have improved their generating plant's performance:

1. Performance improvement can be achieved.
2. Performance improvement requires a systematic, comprehensive and continuous program with strong commitment from executive management.
3. A strong data collection and analysis program is a vital element in any successful Performance Improvement Program.
4. Some equipment replacement, refurbishment or upgrades will be required.
5. The majority of the focus should be on improving management practices.
6. The addition of advanced technology power plants combined with improvement in management practices are complementary pieces of the total improvement puzzle.
7. New advanced technology plants will only reach their full inherent design potential if the most effective management practices are applied.
8. Performance improvement of existing power plants is a proven, cost-effective way to increase the energy producing capabilities of a utility while producing substantial environmental benefits.
9. A successful Performance Improvement Program starts with creating the awareness in the minds of generation executives and staff of the potential for improvement and its value to the company and the country.
Appendix 9 – Consultants CV

Robert R. Richwine, Jr.

*Power Plant Reliability Management Consultant*
Managing Partner, Richwine Consulting Group, L.L.C.

B.S., Aerospace Engineering, University of Alabama, 1966

Various Aerospace firms from 1966-1975

Joined Southern Company in 1976

Transferred to Southern Energy (originally part of Southern; now Mirant) in 1993

Independent Consultant since 2002

- Availability Improvement
- Reliability Analysis
- Economic Evaluations
- Reliability Data
- Decision Support Tools
- Benchmarking studies

Upon leaving Mirant in 2002, Mr. Richwine has performed numerous consulting assignments, including projects for AES (plant performance improvement - ongoing), the International Atomic Energy Agency (inventory management), TVA (benchmarking), Mirant (reliability models and long term non-recurring cost estimating), Ireland (benchmarking) and PowerGen of Trinidad. Mr. Richwine is partnered with the North American Electric Reliability Council (NERC) in offering advanced benchmarking services (see [http://www.nerc.com/~gads/benchmarking.html](http://www.nerc.com/~gads/benchmarking.html)) and delivers performance improvement workshops around the world for the World Energy Council.

From 1993 to 2002 Mr. Richwine was assigned as in-house consultant to Mirant’s (formally Southern Energy) power project development group. He was responsible for initial assessments of technical performance and on-going cost of potential power projects. In addition, he provided support to the Consulting Department on contracted projects and provided input on new business line development. He also supported Operations and Trading and Marketing Risk Management.

Before transferring to Southern Energy, Mr. Richwine was consulting reliability engineer at Southern Company Services in Birmingham, Alabama. After joining the firm in 1976, Mr. Richwine organized the company’s Reliability Engineering group and progressed in increasing levels of responsibility until his departure for Southern Energy, Inc. in 1993. During these 17 years Mr. Richwine was involved in the development and implementation of numerous programs and projects that have seen the southern electric system’s coal-fired plant’s availability increase from 68% in 1976 to over 92% by the late 1980’s. Among these projects were the development and implementation of the company’s Availability Improvement Program; Reliability, Availability, Maintainability (RAM) analysis; availability/reliability projections for existing/proposed power plants; Coal Quality Impact assessments; automated maintenance management systems; capital budget economic evaluations; maintenance optimization decision
support tools; and new plant goal setting/performance monitoring management systems for
which he received The Southern Company Chairman’s Excellence Award in 1995.

In addition, Mr. Richwine has acted as a consultant for Southern Energy, Inc. to numerous
United States and international utilities including the New England Power Company, the New
England Power Pool, the Electricity Supply Board of Ireland, the Puerto Rico Electric Power
Authority and others. He has served as chairman of the North American Electric Reliability
Council’s (NERC) Generating Availability Trend Evaluation (GATE) working group and as
chairman of NERC’s Fossil Design Review Task Force and was closely involved in the
development of NERC’s Generating Availability Data System (GADS).

He is currently a member of the World Energy Council’s (WEC) Committee on the Performance
of Generating Plant and publishes case studies on the use of performance data in improvement
efforts on the WEC website http://www.worldenergy.org/forward.asp?page=ppp. In addition he
is working with the WEC to develop a worldwide power plant performance data recording
system. He has recently delivered workshops at various venues around the world on power plant
data and performance indicators and advanced concepts in benchmarking those indicators for
both traditional regulated generating companies as well as market-based companies. He has
served as an expert witness in arbitration cases regarding power plant performance indicators and
was a member of the IEEE – 762 Committee responsible for revising the standard of power plant
reliability metrics.

He has served as Chairman of the International Atomic Energy Agency’s (IAEA) Advisory
Group charged with developing a project to collect international Operations and Maintenance
cost data for nuclear power plants worldwide. In addition, he has acted as a consultant to the
United Nations Development Program (UNDP) on its Market-Based Power Plant Management
project for the Peoples Republic of China.

During the first 10 years of Mr. Richwine’s career, he worked with several aerospace
engineering companies on projects such as the Apollo program, the DC-10 aircraft design and
Pratt-Whitney aircraft engines and aircraft derivative power generation turbines.

Mr. Richwine is the author or co-author of over 30 technical publications on the subjects of
Availability Improvement, Reliability Engineering, and cost/performance relationships for power
plants.

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